WORLD BANK WORKING PAPER NO. 8

Private Sector Participation in the Power Sector in Europe and Central Asia

Lessons from the Last Decade

Venkataraman Krishnaswamy
Gary Stuggins

THE WORLD BANK
Washington, D.C.

1 2 3 4 05 04 03

ISBN: 0-8213-5529-5
eISBN: 0-8213-5530-9
ISSN: 1726-5878

Venkataraman Krishnaswamy is Consultant in the Infrastructure and Energy Services Department in the Europe and Central Asia Region at the World Bank. Gary Stuggins is Lead Energy Economist in the Energy Unit of the Energy and Water Department at the World Bank.

Library of Congress Cataloging-in-Publication Data

Krishnaswamy, Venkataraman, 1934-
Private sector participation in the power sector in Europe and Central Asia: lessons from the last decade/ Venkataraman Krishnaswamy, Gary Stuggins.
p. cm. -- (World Bank working paper; no. 8)
Includes bibliographical references.
ISBN 0-8213-5529-5
1. Electric utilities--Deregulation--Europe. 2. Electric utilities--Deregulation Europe, Eastern. 3. Electric utilities--Deregulation--Asia, Central. 4. Privatization--Europe. 5. Privatization--Europe, Eastern. 6. Privatization--Asia, Central. I. Stuggins, Gary II. Title. III. Series.

HD9685.E82K75 2003
333.793'2'0947--dc21

2003049710

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Foreword

This brief desk research study reviews the experience of the Bank's operations in the electricity sector in ECA countries during the 1990s. The operations during this decade focused on sector restructuring, privatization, and introduction of competition to improve the performance of the sector. These efforts met with a measure of success in certain countries and great deal of difficulties and problems in others. Four case studies relating to countries which are preparing for EU accession and six case studies relating to former Soviet Union countries have been prepared; based on these studies and on the information relating to other countries, lessons have been drawn on the sequence of reforms and essential preconditions for success. Key lessons relate to the importance of legal reform, tariff reform, social protection measures, and comprehensive commercialization of the operations of the utilities *before* undertaking structural changes, introduction of competitive markets, and privatization. The study highlights the importance of not using any single model of reform in all countries and the imperative need to design the content, the level of sophistication, sequencing, and timing of the reform package for each country based on the endowments and the conditions prevailing in that country. In particular, the importance of choosing market structures appropriate to the circumstances of each country has been emphasized. Good practices enabling successful and sustainable privatization of power sector assets to strategic investors and securing optimal privatization receipts have been identified.

In the context of declining interest of strategic investors in the emerging markets, the present report is topical and should help staff in refocusing their attention to the core objectives of the Bank's operations, and preparing the utilities and the sector more fully for privatization when the investor interest revives.

Hossein Razavi
Director
Infrastructure and Energy Services Department
Europe and Central Asia Region

Executive Summary

Introduction

The focus of the Bank's operations in the electricity sector shifted in the late 1980s from financing projects and programs seeking to improve the performance and efficiency of the utility and the sector to financing government programs. These programs were designed to restructure the sector to enable the provision of electricity services by the private sector in a competitive milieu. At the beginning of the new century, the appetite of strategic investors for the emerging market utilities seems to have declined. Some of them have disinvested their recent acquisitions and most of them appear to have overstretched themselves. Opportunities and returns available in the developing world appear to them more risky and less rewarding.

The Californian power crisis appears to have greatly rekindled the latent doubts on moving to more competitive market structures for such an essential service as electricity. The recent collapse of Enron and several other industrial giants, as well as doubts about the reliability of external audits (resulting, in particular, in the collapse of Arthur Anderson) and the slide in the stock values of AES and other companies has eroded the confidence in the institutional pillars of the market, such as corporate disclosure, external audit, and oversight by regulators and Security Exchange Commissions. Major energy investors, at least in North America, seem to be anxious to clean up their balance sheets to eliminate from their portfolio unprofitable and risky investments.

Against this backdrop, the objective of this study is to review the experiences in the ECA region[1] in the 1990s in relation to the private sector participation in the power sector and draw possible lessons and to identify the approaches that enable successful privatization of the power sector and securing optimal privatization receipts. Brief case studies for 10 countries, essentially based on a desk review of the Bank's available records, were prepared, and information on a few other countries was collected. The emerging findings and preliminary insights were shared with a wide range of Bank staff in a well-attended brainstorming session in July 2002, and the decision draft of the report (prepared on the basis of reactions and suggestions received in that session) was circulated widely within the Bank and discussed in a meeting in October 2002. The final version has been prepared after taking into account the comments made in that meeting, as well as the comments received from select Country Directors or their staff and other comments received from within and outside the Bank.

Common Features

The countries for which case studies were prepared are: (a) Hungary, Lithuania, Poland, and Turkey - all candidates for EU accession; and (b) Georgia, Kazakhstan, Kyrgyz Republic, Moldova, Tajikistan, and Ukraine – all former Soviet Union countries. Some of their common relevant features are:

- All of them (except Turkey) went through the political and economic upheaval of the early 1990s and have recovered or are recovering from them at varying paces.
- Turkey had its own series of periodic economic crises and is recovering from them.
- In all of them, nearly 100% of the population has access to electricity and the sector does not suffer from the burden of having to extend supplies to new uneconomic areas.
- All of them had a fairly high level of technical competence but had the need to develop skills necessary to operate in a market.
- Most of them have excess generation capacity and declining or stagnant demand. In Turkey, demand growth levels assumed while contracting with independent power producers (IPPs) turned out to be too optimistic.

1. Europe and Central Asia Region of the World Bank which covers most East European countries, former Soviet Union (FSU) countries and Turkey.

- Most of them (especially the FSU countries) had high levels of system losses and theft; they faced very high levels of non-payment and payment through barters, offsets and similar methods of non-cash payment.
- Power systems of Poland, Hungary, Ukraine, Turkey, and Kazakhstan are large and can easily support a competitive market by themselves, while the sizes of the power systems of the remaining five countries are relatively small, and introduction of competitive structures would appear, prima facie, unpractical except in the context of significant import dependence.

Range of Experience

Briefly, the range of experience includes:

- Kazakhstan privatized quickly most of its generation and some of its distribution at "throw-away" prices, and now it operates a bilateral contract driven wholesale market. Some of the investors have disinvested and walked out.
- Tajikistan and Kyrgyz Republic have either unbundled or are considering unbundling their sector and have not undertaken any privatization yet. The planned concession for Pamir Power Company to operate as a vertically integrated utility in Tajikistan would be the first case of private investment.
- Turkey and Lithuania have substantially commercialized and unbundled the sector and are poised to introduce competitive wholesale markets.
- Poland and Hungary have unbundled the sector, introduced a single buyer model wholesale market and have substantially privatized generation and distribution.
- Ukraine has unbundled and adopted a sophisticated competitive pool (which could not work as envisaged on account of extensive non-payment problem) and has privatized more than 50% of its distribution. It is still searching for a workable model.
- Georgia has unbundled and privatized distribution in its capital region and some generation. It has given management contracts to manage non-privatized generation, transmission, and the Wholesale Market Operation and operates a single buyer model pool.
- Moldova, the smallest among the countries reviewed, has unbundled its sector, has privatized three of its five distribution companies, and operates a wholesale market based on bilateral contracts between distributors and domestic and foreign generators.
- Hungary, Poland and Turkey started with BOT/BOO/TOOR type[2] of private sector involvement and are devising methods to accommodate them in a competitive structure and to manage the resulting stranded costs/contracts.

The lessons and findings based on a review of these 10 countries as well as those of a few others such as Armenia, Albania, Romania, Russia have been grouped into five chapters in Part I of this report. The case studies relating to the ten countries have been given in Part II.

Getting the Conditions Right

The key lessons and findings under this group are:

- When the country is experiencing a deep and prolonged economic and political crisis and is focusing on stabilization, introduction of sector unbundling, competitive markets, and privatization for the power monopoly is counterproductive. It is good to wait for the economy to stabilize.

2. BOT- Build, operate, and transfer; BOO- Build, own, and operate; TOOR- Transfer of Operating Rights.

- When a country is reeling under serious and prolonged non-payment and non-cash payment crisis (induced mainly by secular GDP contraction, runaway inflation and stabilization efforts[3]), sector unbundling may actually exacerbate these problems. It is better to focus during this period on the macroeconomic factors causing the systemic non-payment problem, eliminate constraints (legal or political) to denial of service to defaulters, promote budget discipline to eliminate payment defaults by government agencies, and improve procedures to recover debts and related measures.
- Sector unbundling and competition evolved in the developed countries to achieve further efficiency gains, after they had reached practically the full potential for efficiency gains under the regulated monopoly regimes.
- ECA countries have a long way to go to reach that level under monopoly operation. A key lesson from the ECA experience is that attempts at restructuring, privatization, and competition have a chance to succeed only when they are preceded by comprehensive "commercialization" of the operations of the existing utility. Such commercialization is important to attract the strategic investors, to optimize privatization receipts, and to make the transition to the private sector operations smooth.
- Three key steps to precede restructuring and competition are: (a) legal reforms; (b) tariff and regulatory reform; and (c) commercialization of operations.
- Legal reforms aim at making electricity supply a fully commercial service available only to those who pay the bills. They should enable denial of supply to those who do not pay, make theft of electricity a criminal offence punishable with fines and jail terms, and enable speedy recovery of arrears.
- Tariffs should be adjusted to cover the cost of supply and to reduce, to the extent possible, internal cross subsidies; the process of tariff adjustments should be de-politicized through the establishment of professional and independent regulatory bodies. Tariff unbundling (i.e., final tariff = generation tariff + transmission tariff + distribution tariff + customer related costs) helps make price setting more transparent. Tariff reform must include social protection measures for the targeted poorer segments of the society.
- Some of the key elements of commercialization are: (a) cutting the utility from routine annual budget support and compel it to operate with the revenues it generates, (b) functional accounting to identify costs and revenues by function, (c) tariff unbundling, (d) organizing generation, transmission, and distribution functions by business units within the framework of the existing company, (e) evolving transparent transfer pricing among the business units and contract based relationships among the business units, (f) developing meaningful internal and external audits and disclosure procedures, (g) compilation of clear, comprehensive, and unambiguous inventories of all real and fixed assets and debts, and (h) improve metering, billing, and collection procedures and mechanisms to monitor payment defaults and take corrective actions.
- Once the utility has been substantially commercialized and the tariff regimes (including social protection measures) are appropriate, the utilities can access the debt markets on the strength of their balance sheets. This is the appropriate time to consider legal unbundling and privatization. At this stage the unbundled entities will attract competition from strategic investors.

If it is difficult to commercialize the utility under current management, then the use of leasing/ concession arrangements for preparing the utility for asset divestiture could be considered. Inter-utility cooperation and franchise arrangements could also be useful options.

3. For a more detailed discussion of these aspects and especially the impact of certain stabilization efforts on non-payment, please refer to World Bank Technical Paper No.423 of 1999, *Non-payment in the Electricity Sector in Eastern Europe and Former Soviet Union Countries.*

Getting the Market Structure Right

The lessons and findings under this heading include:

- Unbundling and competition are still very much work in progress all over the world and not a finished product; a unique model, which would apply to all countries and at all times does not exist. Market structure suitable for the current stage of economic and political development of the country and the size and features of the power systems should be decided upon for each country.
- For reasonable competition a good rule of thumb may be that no single entity should operate or control more than 20% to 25% of generation or distribution. Thus if the size of the system cannot accommodate four or five generation companies and four or five distribution companies, and if no competition could arise from cross-border demand or supply,[4] then it is time to consider carefully whether unbundling and competition would work in that country.[5] We have to look for simpler market structures.
- In the case of small systems (below say 3000 MW), which have no ambitions to accede to the EU, which do not form part of any logical larger international grid, and which have no significant electricity import-export possibilities, one should be wary of unbundling, as transaction costs may be too high and scope for competition would be severely limited or nonexistent. It is probably better to handle such a small system as a vertically integrated utility (VIU) and privatize it as it is.
- It is necessary to avoid fragmenting the distribution segment into far too many tiny and unviable entities (as preferred by many ECA borrowers), as such tiny entities do not attract any serious investors. A viable distribution utility should have no fewer than about a million consumer connections and a volume of sales of at least 2 TWh to attract strategic foreign investors.
- A single buyer model (where the dispatch is on the basis of Power Purchase Agreements with generators) is simple and preferred by many countries, but it makes the introduction of competition later very difficult. PPAs established on a "take or pay" basis create rigidities and can lead to serious stranded costs, which make privatization and competition unpalatable, unless such PPAs have been structured in ways to make them market-friendly.[6]
- One should be wary of the Hungarian type single buyer market model in which the government is able to give private investors in generation and distribution their promised return on equity while holding down retail tariffs and subsidizing the state-owned single buyer through direct and large subsidies from the state budget.
- The balancing market should be simple to start with.
- It is better to allow the market to take the generation capacity addition decisions than to allow the transmission company or the regulator to make such decisions
- There could be tradeoffs between "ease of privatization" and introduction of competition. A choice as to which is more important has to be made for each country at the start of the reform process.

In the countries that wish to join the EU, the market structure is likely to be one of coexistence of liberalized and regulated segments of the markets, especially in the light of anxieties induced by California experience.

4. Moldova and Albania are cases of small systems, which have potential for competition on account of dependence on imports.

5. In a good competitive market, four or five companies should compete not only for base load power, but also for peaking power and intermediate power (i.e., all along the load curve).

6. See Fiona Woolf and Jonathan Halpern, *Integrating Independent Power Producers into Emerging Wholesale Power Markets*, World Bank Working Paper No. 2703, November 2001.

Private Sector Participation

The key findings under this heading include:

- Privatization should follow reforms, not precede them and should be undertaken in a transparent manner to maximize the value of the transaction (e.g., avoid the kind of problems experienced in Kazakhstan).
- IPP contracts with their guaranteed "take or pay" provisions (insulating the generator from demand risk, dispatch risk, price risk and exchange rate risk) are a major hindrance for further sector reform involving competition, unless they are structured in ways to make them market-friendly.
- In the context of liberalization of the markets, some countries have succeeded in renegotiating these IPP contracts, because of the change in regime and on the basis of the risks being reallocated equitably between the two parties.
- Transfer of Operating Rights (TOOR) practiced in Turkey is a variation based on leasing, which was resorted to because of constitutional prohibitions of outright sale of electricity assets. This proved to be complicated; TOORs are presently being phased out, since the government succeeded in getting the constitution amended.
- Privatization through transparent international competitive bidding among pre-qualified investors results in optimal privatization receipts and sustainable privatization deals. Negotiated privatization does not even save time (e.g., Estonia) and often leads to unsatisfactory terms.
- Issue of shares to employees (10 to 15%) and through local stock exchange (15 to 20%), as is widely practiced in ECA countries, is probably good for the employees morale and for the stock markets, but combined with minority share privatization they tend to give control of the company in unintended ways. They tend to be unattractive to serious investors, since groups with minority blocking rights[7] can always hinder whatever good the strategic investor wants to carry out (as happened in Ukraine).
- It is always effective to offer majority shares to attract strategic investors in a manner that enables them to implement prudent investment and operating decisions. In any case the strategic investor must have management control.
- Selling all the shares to the strategic investor retaining only a golden share (or some similar device, such as a special shareholder agreement) may be a prudent option. It will also help the government to prevent acquisitions and mergers eroding competition.
- The privatization agreement may also contain a prohibition for the resale of assets to anyone with qualifications inferior to those of the original investor. Otherwise the elaborate pre-qualification exercise would become meaningless.
- It is more difficult to sell generating units which need to function as merchant plants in a competitive market than those which can function as a part of a vertically integrated operation, can supply to their own distribution utility, or can have bilateral contracts with distribution utilities and large industries.
- Saddling generation units with the ownership of coal or lignite mines makes privatization difficult.
- It is good practice to sort out labor agreements (re: employment levels, severance compensation, funds for assisting separated labor), issues related to associated coal or lignite mines, and discontinuation of fuel "allocation" practices before starting privatization. Poland and Hungary provide different examples for this purpose.

7. These are groups which manage to acquire 25% plus one share through purchases from the employees and other individuals.

- While privatizing distribution utilities, issues relating to the "right of way" vis-a-vis the facilities located in state or municipal lands and issues relating to the quenching of any legal rights the municipalities may have in relation to distribution business and related power facilities should be sorted out in the pre-privatization phase. Special legislation appears to be necessary for this in most ECA countries.
- It is good practice to prepare and include in the privatization documents comprehensive inventory of assets being sold (for example, "include all relevant feeders and not let the new owner to fight for every feeder with some reseller"), debt inventories and debt restructuring plans, and clearly laid out tariff policies.
- In order to reduce the regulatory risks, it would be useful to examine whether detailed tariff principles and the actual formulae could be built into the privatization contract.[8] Most regulatory bodies are new and are subject to political pressures; they may take a few years to settle down to the routine of independent regulation.
- Establishment of an independent regulatory body with adequate financial and personnel resources and the issuance of clear and fair tariff guidelines and methodologies improve the prospects of privatization (example of Ukraine in the last round of distribution privatization).
- Provision for international arbitration makes it easier to attract strategic investors (e.g., Turkey). Recourse to an Appellate Tribunal has also been found to be helpful in many Latin American countries, India, and USA.
- The concept of strategic investors (mostly from West Europe or North America) being selected on the basis of competitive bidding was working well till recently. Increasingly, tenders issued do not elicit any response (e.g., Georgia, Armenia, Czech Republic, and several other countries). Diversification appears to be necessary, and efforts have to be made to look for investors also from Australia, Japan, Latin America, and Asia. Local and regional entrepreneurs (and financial investors from any part of the world) with proven resources and with firm technical collaboration or joint venture agreements with strategic investors are resources that should also be mobilized. Competitive bidding is still the preferred approach.
- One needs to be wary of dishonest and collusive equity for debt swaps and asset stripping as was practiced in Ukraine.
- In the context of lack of interest on the part of the strategic investors, it appears worthwhile to encourage 'franchising' and second best solutions, such as concessions, leasing, and management contracts, as interim solutions.
- The best insurance against the present lack of investor interest is to focus on continued commercialization (if necessary, using concession/leasing arrangements, management contracts, inter utility cooperation, etc), improve corporate governance and take the utility up to the stage of its being able the provide the equity from the internally generated cash for the investment needs and being able to access the debt market on the basis of its credit rating (e.g., Lithuania).

The responsibilities of the government do not cease upon privatization and its oversight role often becomes more complex. The government has to maintain stable sector policies and keep the letter and spirit of the privatization agreement and work jointly with investors to solve local problems as they arise. Continued fair and transparent mechanisms for dispute resolution need to be maintained. It should quickly adapt to the concept of the independent functioning of the regulatory body. It should avoid actions that go against the spirit of privatization agreements. The action of Hungary to raise the wholesale tariff at a certain rate and allow retail tariffs of distributors at a lower rate, and the actions of Ukrainian government in preventing and later staggering retail tariff adjustments called for in the tariff compacts of the privatization agreements are the types of post-privatization actions to be avoided if one is to retain investor confidence.

8. See Bernie Tenenbaum, Regulation by Contract, forthcoming publication in the World Bank Energy Sector Board Series.

Social Safety-Net Issues

Key lessons under this heading are:

- Privatization plans should include comprehensive measures to deal with the problems of redundant labor and managers, their relocation, training, and redeployment.
- The indiscriminate "privileged" tariff discount system used in most FSU countries must be fully eliminated.
- Tariff increases and reduction of cross subsidies should be gradual and phased and not be at a pace excessively faster than the pace of income growth.
- The target poverty group to be protected against rising tariffs for electricity and other forms of energy should be carefully determined on the basis of household income and expenditure surveys.
- Direct income supplements to the target poverty households through social security system should be provided without distorting the tariffs of utilities.
- Pending the implementation of such a social safety net, sub-optimal solutions, such as lifeline tariffs, energy vouchers, etc., could be considered and implemented respecting the property rights of the utility operators.

Conclusions

- Overall during the 1990s, the privatization agenda proceeded somewhat ahead of the abatement of the economic turmoil and proper stabilization of the economies, and the abatement of the severe non-payment and non-cash payment problems caused by macroeconomic factors.
- The privatization agenda involving sector unbundling and introduction of competitive markets must carefully proceed after the much-needed comprehensive commercialization of the sector, tariff reform, social safety net reform, and the stabilization of the functioning of the newly created regulatory bodies.
- Privatization took place at a pace and in a manner that resulted in a substantial cost of low privatization receipts. The agenda of introducing a sophisticated competitive pool type of market, regardless of the size of the systems, scope for competition, level of political development, and institutional maturity appears to have been premature in some countries and inappropriate in some others.
- The willingness and ability of the strategic investors to absorb all the risks and rush to buy the assets offered for sale appear to have been overestimated.
- The speed or the slow pace of reform in various countries may, among other things, be a function of the extent of correctness of these judgments.
- As in general economic development, there are clear stages of development of the electricity sector. In the basic stage, the utilities are state-owned and operate as government departments with no commercial focus. In the second stage, they become commercially viable and socially responsible public sector companies operating fully on commercial lines, covering their cost of supply (including the cost of capital). In the third stage, they become privately owned competitive entities. Attempts at leapfrogging from the basic to the ultimate stage do not appear to have met with much success. This is an important lesson from our experience in ECA countries in the 1990s.

Recommendations

The reform package must be tailored for the circumstances of each country, and no single model would fit all countries. Within this framework the countries considered fall conveniently into two groups, namely the EU accession countries and others. The EU accession countries have a more appropriate legal infrastructure, a better understanding of the concept of property rights, and are more exposed to market mechanisms than the other countries. They have also made substantial

progress in matters relating to utility efficiency, tariffs, social protection, and sector restructuring. Also they have chosen to join the EU, which requires them to achieve a level of sector reform and liberalization before their accession.[9] The other countries are in a different situation. Thus it is possible to provide different recommendations for these two groups of countries.

1. For EU accession countries: Given the expectation that western Europe will move to a regional competitive market, EU accession countries must prepare their utilities to be sufficiently efficient to be able to compete in such a market. To accomplish this, they should focus on unbundling, regulated or free third party access to the grid, coexistence of regulated and competitive markets side-by-side, and freedom for eligible consumers to choose their suppliers from within the country or abroad. In these cases it is sensible to proceed with the privatization agenda and have all distribution and generation privatized to enable meaningful competition within and outside the country.
2. For other countries: The focus must be on full commercialization including tariff reform and social protection measures, especially in the context of investor indifference. Concessions and leasing arrangements can be as useful mechanisms for engaging private sector participation as asset sales. Sector unbundling should follow such commercialization where appropriate and operations of unbundled entities, if necessary, can be improved on the basis of management contracts when other private sector options are not possible. Energy reforms should also focus on improving governance structures and corporate governance. Under these circumstances they can afford to wait till the investor interest revives.
3. For the Bank: It is good to realize that sector reform is a long haul operation lasting for well over a decade (unbundling - two-three years, market design and operation - three years, privatization - two-three years, regulatory reform – two years, etc.) and provide for the Bank's continued involvement through appropriate sector-related instruments (SECALs, Programmatic Loans, sector studies and technical assistance) and, equally importantly, devise some continuity of personnel and institutional memory.
4. For the Bank: There is a need to monitor the performance of privatized entities for a few years to learn whether the expected efficiency improvements took place or not and understand the reasons in cases of failures.

9. Poland and Hungary have completed privatization substantially.

CHAPTER 1

INTRODUCTION, BACKGROUND, AND METHODOLOGY

The Approach in 1990s and its Rationale

The focus of the Bank operations in the electricity sector shifted in the late 1980s from financing projects and programs (seeking improvements in the performance and efficiency of the utilities and the sector) to providing budget support to governments to restructure the sector enabling the provision of electricity services by the private sector in a competitive milieu.

This was partly a consequence of the Bank's strategic choice of emphasis on poverty reduction and partly a consequence of the remarkable conceptual and institutional changes taking place in the sector in a few countries in 1980s. The strategic emphasis on poverty reduction created an urgent and pressing need for the re-prioritization of the state's roles and activities for the allocation of the state's scarce resources. The responsibility for investments and operation in the highly capital intensive electricity sector was adjudged in this context to be that of the commercial private sector, rather than that of the state, strapped for resources for the urgently needed human development activities aimed at poverty reduction. The sale of the power sector assets to the private investors would not only give the state immediate resources to meet its poverty reduction related investments, but would also free the state from the obligation to finance future power system needs. Further the investment needs of the power sector were estimated to be substantially larger than the public sector financing capacities and what the multilateral lending agencies could provide. Also, private investors would be more willing to invest in physical infrastructure like power, rather than in social infrastructure like basic education or public health.

In the past the power utility business was considered a natural monopoly, a condition of market imperfection warranting state intervention by direct state ownership or by state regulation. This theoretical basis came to be challenged in the 1980s, when technological innovations in power generation and institutional innovations in certain countries demonstrated that monolithic utilities could be vertically unbundled by function, viz., generation, transmission, and distribution and that generation and distribution functions (horizontally split into several entities and owned by different investors) could well be operated on the basis of competition among multiple owners.

In the 1990s most of the electricity related operations of the Bank in the Europe and Central Asia (ECA) countries (and in other regions too) focused on the creation of independent regulatory bodies and efforts to unbundle the sector, privatize generation and distribution, and operate the sector on competitive basis. It was further believed that privatization is best done through competitive bidding among pre-qualified strategic investors, on the basis of the selected investor acquiring majority shares and management control. Some measure of success has been achieved in certain countries, while major problems have been encountered in many others.

Current Situation

At the beginning of the new century, the appetite of the strategic investors for the utilities in the emerging markets appear to have distinctly declined. Some of them have actually disinvested their recent acquisitions and many of them appear to have overstretched themselves. Opportunities and returns available to them in the developed world appear to them to be less risky and more rewarding. Most of the energy investors, at least in North America, seem to be anxious to clean up their balance sheets to eliminate from their portfolio unprofitable and risky investments.

The power crisis in the competitive power sector of California, and the problems faced in other parts of the world such Alberta, Canada, and New Zealand, in the operation of competitive markets greatly rekindled the latent doubts on the sole reliance on the competitive market for such an essential service as electricity. These debacles highlighted the complexities of competitive markets and the need for highly sophisticated oversight mechanisms to keep in reasonable check the natural tendency to maximize profits through short cuts such as cartelization, manipulation of markets and prices and the constant attempt to "rebundle" through holdings, acquisitions and mergers, to gain market power and advantage at the expense of the consuming public and at considerable cost to the society.

The recent collapse of Enron and several other industrial giants, as well as doubts about the integrity of external audits resulting in the collapse of Arthur Anderson, and the slide in the stock market values of AES and other electricity investors in emerging markets has rudely shaken the confidence in the institutional pillars of the market, such as corporate disclosures, external audits, and oversight and regulatory bodies such as the Security Exchange Commissions. The sudden and shocking failure of the telecom giant WorldCom raised serious doubts about the wisdom of entrusting such vital services as telecom and electricity (with serious implications and linkages to strategic state security) entirely to markets. The revelation of the limitations and weaknesses of private investors and oversight mechanisms in general, and those of strategic energy investors in particular, have created conditions under which the Bank may have to revisit the concept of exclusive reliance on strategic investors and pay renewed attention to, and emphasize governance issues, irrespective of ownership.

The Limitations of the New Sector Reform

While admittedly a great deal of progress had been made in some parts of the world in the operation of electricity markets on the basis of competitive pools and in providing choice of suppliers to an increasing percentage of consumers, practical difficulties and political risks involved in applying them as a universal solution to all countries are becoming clearer.

- Most of the developed countries had already achieved a high degree of efficiency within the framework of vertically integrated utilities and had cost recovery tariffs before they moved towards competitive models in search of further improvement in efficiencies and lower electricity prices. It is still not clear whether in these countries reductions in electricity prices in real terms have been achieved, taking into account stranded cost and stranded debt recoveries.
- The actual number of consumers exercising the provided choice and making changes of suppliers also seem to be small.

- Similarly the impact of this kind of reform on the quality and reliability of supply still remains to be proved as benign. In some cases, one witnessed, at least in initial stages, the strange coexistence of high stranded capacities and system outages caused by lack of capacity.
- The effectiveness of the competitive market is founded on the ease of entry and exit of generators. In countries that had no natural gas reserves or had no access to them this would be a problem. Capacities based on other[10] tend to be large in size (to exploit economy of scale) and generally have lead times of 3 to 5 years to commission.
- In most developed countries, electrification of the country is nearly complete, demand growth is moderate and supply and demand tend to be in equilibrium facilitating competition. In the developing countries the electrification of the country is partial and, in general, capacities are not adequate to meet growing demand, and shortage situations not conducive to competition prevail.
- Tariffs in developing countries are well below costs of supply and prices cannot do anything but go up steeply when privatization and competitive markets are introduced, especially in the shortage situation which prevails in these countries.
- Most developing countries have to go a long way before achieving the full efficiency potential available within the framework of vertically integrated utilities.
- Operation of competitive electricity market calls for a culture and tradition of respecting property rights, and obligations under contracts as well as the availability of legal infrastructure through courts and arbitrations for dispute resolutions in a rapid, fair and competent manner, and mechanisms to enforce court decisions and property rights, and these are not easily or fully available in many developing countries.
- Countries with small power systems, cannot make use of this alternative, as their systems would be too small to accommodate a sufficient number of competing service providers to clear the market.

Study Methodology

Against this backdrop, the objective of the present study is to review the experiences in the ECA region in the 1990s in relation to sector reform and private sector participation and draw possible lessons. Case studies were carried out for 10 countries essentially based on a desk review of the Bank's available records, supplemented by information available in the Internet. Many of the newly created regulatory bodies and their association, as well as many utilities and governments maintain web sites giving useful information. Discussions with individual Bank staff with operational responsibilities provided useful insights and needed corrections. The case studies are presented in Part II of this Report. Preliminary findings based on nine of these case studies and case studies themselves were widely circulated among all relevant staff and divisions in the Bank Group and discussed in a well-attended brain storming session on July 16, 2002. The comments and reactions from those who attended the session and the comments sent by mail by those who could not attend the session were taken into account in preparing the decision draft of this Report. The decision draft was widely circulated within the Bank Group and discussed in a meeting on October 30, 2001. The present Report was finalized on the basis of decisions arrived at that meeting. Comments by peer reviewers, and from select country departments of the ECA region, as well as those from outside the Bank (e.g., EBRD and USAID) were specifically sought and taken into account. The countries for which case studies were carried out are: (a) Hungary, Lithuania, Poland, Turkey - all candidates for accession to the European Union (EU); and (b) Georgia, Kazakhstan, Kyrgyz Republic, Moldova, Tajikistan and Ukraine- all former Soviet Union countries. Some of their common relevant features are:

- In all of them, nearly 100% of the population has access to electricity and they do not face the burden of extending electricity supplies to new uneconomic areas.

10. Diesel fueled generators are an exception but they are limited to smaller capacities.

- All of them, except Turkey, went through the economic and political turmoil in the early 1990s involving major GDP contraction, hyper inflation, and steep devaluation of local currencies and have recovered or are recovering from them in varying degrees.
- Turkey had its own series of periodic economic crises and recovery from them.
- The utilities in these countries had staff with a high level of technical competence, but needed to acquire skills required to operate in a market milieu.
- Most of them had declining or stagnant demand for electricity and had excess generation capacities. In the case of Turkey the actual demand growth turned to be much lower than that assumed for contracting for substantial IPP capacities.
- In most of these countries the consumption mix underwent a dramatic change with a significant increase in the share of consumption by households and a significant fall in the share of industrial consumption.
- All of them (especially the FSU countries) suffered from high levels of system losses and most of them from poor collections and extensive use of barter, offsets and other forms of non cash payments.
- All of them (except Turkey) went through voucher privatization and allotment shares to utility managers and staff leading initially to insider control, unhealthy management practices and corruption.
- Power systems of Poland, Hungary, Ukraine, Turkey and Kazakhstan are large and could support a competitive power market, while those of the remaining 5 are small and prima facie, would not be considered capable of supporting a national competitive market, except in the context of heavy import dependence.

The range of experience among these countries include:

- Kazakhstan privatized most of its generation assets and nearly half of its distribution assets at throwaway prices, simply to get the system operational. Privatization actions were undertaken ahead of any strategic thinking or planning for the market structure and operations. It is forced to run its wholesale market entirely based on bilateral contracts. Regulation had proved unstable and some of the investors have disinvested and walked out.
- Kyrgyz Republic and Tajikistan have either unbundled or are contemplating unbundling their sector and no privatization had taken place yet. Tajikistan is about to finalize a long-term concession to an NGO-owned Pamir Energy Company to construct a 14 MW hydroelectric station and operate the related isolated system in the Gorno Badakshan area as a vertically integrated utility.
- Turkey and Lithuania have substantially completed the commercialization of their utilities, unbundled the sector by function and are poised to move towards competitive wholesale power markets.
- Poland and Hungary have unbundled their power sector and have introduced a wholesale market on the basis of a single buyer model and have substantially or significantly privatized their generation and distribution assets.
- Ukraine unbundled the sector and adopted a highly sophisticated competitive pool, which could not be operated as envisaged on account of extensive non-payment problem. It has privatized 50% of its distribution assets and is still searching for a workable wholesale market model.
- Georgia has unbundled and privatized distribution around the capital region and also some generation assets. It uses management contracts to manage non-privatized sector assets and to operate the wholesale market on the basis of a model similar to the single buyer model.
- Moldova (the smallest among the countries reviewed) unbundled its sector and privatized 70% of the distribution and is operating a wholesale market based on bilateral contracts between distributors and the domestic and foreign generators.

- Hungary, Poland and Turkey started with extensive private sector involvement in the form of BOT/BOO/TOOR contracts and are devising methods of accommodating these contracts within the framework of competitive pools and managing the resulting stranded costs.

These countries thus provide a range of experience from which a range of lessons could be drawn. The findings relating to these countries and some other countries such as Russia, Romania, Albania, and Armenia for which no full case studies were prepared are discussed in the succeeding chapters focusing on aspects such as: (a) getting the conditions right; (b) getting market structure right; (c) getting the private sector participation right; and (d) getting the social safety net issues right.

CHAPTER 2

GETTING THE CONDITIONS RIGHT

Focus on Stabilization

The experience in most East European and Former Soviet Union countries clearly indicates that it is extremely difficult to carry out structural reforms of the sector and attract private investors during conditions of economic turmoil. In the first half of the 1990s these countries experienced continuous GDP contraction, hyperinflation, massive devaluation of their local currencies, severe fiscal and current account deficits and high levels of unemployment. Countries such as Russia, Ukraine, Georgia, and Moldova had unsettled economic and political conditions during most of the decade, while Hungary, Poland and Lithuania recovered more quickly and resumed growth by mid 1990s. Sector reforms involving unbundling of the sector and privatization of the unbundled entities had been most difficult in countries with a prolonged duration of turmoil and somewhat less difficult in countries (such as Hungary, Poland and Lithuania), which achieved economic stabilization more quickly. Even in Moldova privatization became possible only towards the end of the decade. Kazakhstan could be regarded as an exception to this generalization, as it privatized much of its generation and distribution assets at the height of its economic crisis. However, it sold its extensive assets at a "throwaway price" and did not think through the reform fully, resulting in a chaotic state of the sector and investors pulling out of the country. Reforms of this kind during economic turmoil add significantly to the heavy burden of the people and face hostility and resistance.

Focus on Non-Payment

Both during periods of economic turmoil and some years thereafter, many countries faced a pervasive non-payment phenomenon, which was most acute in the utility sectors. When the Council of Mutual Economic Assistance was dismantled in the early 1990s, traditional export markets disappeared and all imported fuel and energy prices quickly rose to international levels, providing a severe cost-push to electricity and gas prices. With the collapse of industrial production and contraction of GDP, electricity demand dropped, unemployment rose and the ability of people and industries to pay for their consumption of energy was seriously eroded. Tight monetary policies and the need to contain fiscal deficits to fight the massive inflation left the government agencies and state owned enterprises with

no funds to pay for their utility bills. Thus industrial and residential consumers and government agencies defaulted on payments to utilities, which in turn defaulted in its payments to domestic and foreign fuel and energy suppliers, payment of wages to staff, and taxes to the government. Tight monetary policies led FSU states to the extensive use of promissory notes (called vexels in Russia and Ukraine), barter and offsets in lieu of cash for settlement of transactions. Fueled by the scope for corrupt behavior, such non-cash forms of settlements flourished and cash disappeared from the system. In many FSU countries collections were only at 60% to 70% of billings and cash collections were only at 20% to 30% of the billings till late in the 1990s. Russia overcame the problem by about 2000. In Ukraine, Georgia, Moldova and the Central Asian Republics the problem continues even now. The East European and Baltic countries faced this problem only to a limited extent and overcame them well before the mid-1990s and were able to focus on further utility reform through sector restructuring. Most of the FSU countries could not make much headway in attracting private investors on account of the pervasive non-payment problem. Experience in countries like Georgia, Armenia, Ukraine, Kazakhstan and several others showed that sector unbundling in such an environment actually exacerbated the problem, by making it far more difficult for the upstream segments (generating and transmission companies) to access cash. Distribution utilities (DUs) retained whatever little cash they collected and starved the upstream segments for cash. Disconnecting whole distribution utilities for payment default was even more difficult and unpractical than disconnecting individual customers for non-payment. Under such conditions involving severe financial indiscipline, competitive pools or even other modified forms of the wholesale market for electricity could not work as intended in countries like Ukraine, Kazakhstan and Georgia. Thus it appeared that unless stabilization measures succeeded and unless the non-payment situation (caused by macroeconomic factors) is brought under control and payment discipline restored, wholesale electricity markets could not work, seriously threatening the ability of the countries to attract private investors. Under normal circumstances, the private sector, driven by profit motives, is good at ensuring a very good level of collections. It has, however, no magic formula to do that, when the whole country is reeling under economic turmoil and pervasive non-payment induced by macroeconomic factors. In a recent survey conducted by the Bank, 40% of the private investors surveyed considered payment discipline as the second most important among 12 factors and second among three “deal breakers” determining their decision to invest.

The widespread social attitude prevailing in the centrally planned economies of FSU countries (and in some East European countries as well) was that electricity and heat were basic necessities to be provided by the state to all the citizens and were not necessarily commercial services to be provided only to those who pay for them. The Civil Code in Russia till recently made it impossible for the utilities to disconnect supplies to physical persons (residential consumers) for payment default. In respect of legal persons (industries, companies etc), disconnection for payment default would not be possible without their consent! The laws in many of these countries did not explicitly recognize theft of electricity as a cognizable criminal offence, nor the right of the utilities to deny service to those who do not pay the utility bills. Till all such legal lacunae were identified and corrected, and some semblance of payment discipline restored, there was no hope for making any headway with privatization. Proceeding on the basis that restructuring and privatization would somehow help to overcome attitudinal, legal and payment discipline related obstacles and macroeconomic destabilizing factors did not appear to have met with much success in privatization efforts on any sustainable basis. One of the key lessons emerging from the experience in the ECA countries is that during periods of intense economic turmoil and severe non-payment induced by macroeconomic factors, it is prudent to focus on: (a) stabilization efforts, (b) removal of legal, political and attitudinal constraints to denial of service to defaulters, (c) promoting budget discipline to eliminate default by government agencies, and (d) improvement of procedures for the recovery of arrears and debts.

The Fallacy of Reforms Before Commercialization

When reforms involving sector unbundling, privatization, competition and consumer choice were initiated in the developed world, their electricity utilities had practically exhausted the full potential

for economy and efficiency possible under the vertically integrated regulated monopoly model. Their utilities functioned fully on commercial lines and had levels of tariffs adequate to cover fully the cost of supply (including the cost of capital) at high levels of quality and reliability. Reforms in these countries were pursued in search of further efficiency gains and reduction of prices in real terms, not likely to be available under regulated monopoly models. Conditions such as these could well be regarded as necessary preconditions for contemplating competitive electricity markets.

In most FSU countries, however, the utilities were highly inefficient with poor dispatch, high system losses, high levels of theft and extremely poor collections. Their operations were anything but commercial. The levels of their tariffs were well below cost of supply and the tariff structures were characterized by heavy cross subsidies from the industrial to residential consumers. More than half the population was getting substantial discounts even from the low tariffs, by way of "privileged tariffs" as rewards for some achievement or service rendered or as compensation for some disability suffered. These utilities had a tremendous scope for improvements and efficiency gains within their existing monopolistic vertical utility framework, and had a long way to go before contemplating competitive electricity markets.

One of the key lessons that emerge from the experience in ECA countries is that attempts to restructure and privatize the sector have a chance to succeed only when they are preceded by comprehensive commercialization of the operations of the existing utility. Hungary, Poland, and Turkey (as well as Lithuania and Moldova to some extent) focused on: (a) improving their laws on electricity supply and theft; (b) establishing professional and competent regulatory bodies to improve the levels and structure of tariffs to cover costs of supply; and (c) comprehensively commercializing the operation of their utilities. With these reforms, they met with reasonable success in restructuring their sector, attracting private investors and moving towards competitive markets. Ukraine, Georgia, the Central Asian Republics and a number of other FSU states had not focused adequately on the full commercialization of their utility operations before embarking on privatization and are facing: (a) serious lack of investor interest; (b) substantially lower than optimal privatization receipts; (c) investor disenchantment and disinvestments; and (d) stalled reforms and privatization.

Legal Reforms

The private sector cannot function except on the basis of respect for property rights and a legal framework that enables them to collect their revenues and penalizes theft and non-payment. Thus improvements to be made to the legal infrastructure include amendments to the electricity laws to ensure that:

- supply of electricity is a commercial service available only to those who pay the bills for electricity supplied to them;
- the utilities have full freedom to deny service to any consumer who fails to pay his bills;
- procedures for the recovery of arrears are simple, fast and cost effective;
- provisions in the Civil Code or other general laws prohibiting or otherwise discouraging disconnection for payment default are identified and annulled;
- theft of electricity is made a cognizable criminal offence, punishable with heavy fines and jail terms on the basis of speedy trials; and
- the scope for interference by local and federal officials in cases of disconnection or in cases involving prosecution of electricity thieves is eliminated.

In addition budget discipline needs to be instilled to ensure that:

- government agencies get adequate budget provision to pay for their energy consumption;
- they consume within the limits of budget available to them;
- they pay promptly the utility bills using their budget; and
- they are also (like any other consumer) made liable for disconnection of service if they do not pay their bills.

Tariff and Regulatory Reform

The private sector, engaged in regulated activities, cannot function except on the basis of tariffs that allow the costs to be recovered fully. Thus the actions to be taken in respect of tariff reform would include:

- De-politicize the tariff decisions by establishing an independent, professionally staffed, and competent regulatory body;
- Incorporate in the electricity law the principle of regulated tariffs covering the full cost of service including the cost of capital;
- Disaggregate the tariff levels to reflect the cost of supply at various voltage levels, and during peak and off-peak hours;
- Ensure that the regulatory body has stable pricing policies, transparent procedures and is fair to both the service provider and the consumers;
- Eliminate indiscriminate privileged tariff discounts and provide lifeline rates for the targeted poor;
- Minimize cross subsidies in convenient stages.

The credibility, competence and professionalism of the regulatory bodies with adequate and assured financial and personnel resources are key pre-conditions for attracting private sector. Assistance to the governments to enact regulatory laws (a) incorporating sound cost recovery principles applicable to sector segments to be subjected to price regulation, and (b) providing for the operational independence and accountability of the regulatory bodies, and assistance to the Regulatory bodies to enable them to evolve transparent and effective regulations and procedures, provides the best support for the entry of private sector in electricity business. Such a process is equally relevant even when state owned utilities operate the system. Regulatory bodies in Hungary, Poland, Lithuania and Moldova seem to be more professional and appear to be relatively more credible, while those of Ukraine, Kazakhstan and Georgia appear to be subject to greater governmental interference. Romania too appears to have competent regulatory bodies for electricity and gas, though the government seems to feel free to interfere with their independence.

Private investors tend to value the utility, not so much in terms of the book values of fixed assets, but in terms of the present value of future cash flows projected on the basis of the present cash flows. Thus in order to maximize privatization receipts, it is not only necessary to adjust the tariffs to reflect costs of supply, but also ensure that the cash collection efficiency progresses towards the commercially acceptable levels of 95% to 98% of the billings.

Key Components of Commercialization

Other key aspects of the commercialization phase include:

- Cutting the utility off from routine annual budget support. In the centrally planned economies, the losses made by the utilities were addressed by the state budget or by imprudent lending by state owned banks at the end of each year. This has to end; the utility corporatized under the company law and compelled to operate with its own revenues.
- The utility should minimize its cost of supply by least cost operation and dispatch, by reducing its overall system losses (and especially its non technical system losses) to industry norms, upgrading its metering, billing and collection practices to ensure that billing covers 100% of consumption and that collection in cash approaches the industry norm of 95% to 98%.
- The utility should have the freedom to deny supplies to those who do not pay their bills and have efficient procedures to collect arrears.
- Specific and time bound action plans and focus on metering, billing and collection activities to reduce theft of electricity, improve collections and reduce receivables to international benchmark levels.

- Mechanisms to detect payment defaults and monitor corrective action should be introduced.
- Its property registers and inventory of supplies and spares should be fully updated on the basis of full physical verification.
- The utility accounting policies should be aligned more closely to the modern Western utility practices and the IAS to the extent possible.
- Functional accounting needed to identify investments, assets, operating costs and revenues, by function (that is generation, transmission, dispatch, distribution wires services and commercial supply[11]) should be introduced.
- Desirably, the tariffs should be unbundled into generation tariff, transmission tariff, distribution wires tariff and supply business tariff, on the basis of such functional accounts.
- The utility should be reorganized under the same single company into generation business units, transmission business unit, dispatch business unit, and distribution business units in preparation for eventual unbundling of the company. The transactions among the business units should be based on standard commercial contracts and on transfer prices based on industry benchmarks or on normative costs.
- Consistent accounting policies should be used to allocate common costs among the business units.
- Utility should adopt meaningful and effective internal and external audit procedures, based on IAS as well as disclosure policies and procedures commonly used by western utilities.

Another key element of the commercialization phase is the improvement in corporate governance of the utility. Experience in Lithuania shows that appointment of a Board of Directors consisting of outside professionals of high standing and other knowledgeable eminent persons, (rather than limiting the Board membership to a few civil servants and utility executives) has a very healthy impact on the corporate governance of the utility. If for some reason it proves difficult to improve performance with the existing set of managers or the Board, the alternatives of using management contracts or cooperation with or franchising from western utility groups could be considered. Management contracts are considered to be less desirable as they have often not produced acceptable results.

Preconditions for Privatization

Getting the conditions (legal infrastructure, tariffs, regulation and commercialization of the utility) right, after overcoming the economic turbulence and non-payment problem arising from macroeconomic factors is thus a necessary pre-condition for attracting private investors. Attempts to attract the private sector ahead of ensuring such conditions, in the hope that private sector will somehow overcome these obstacles, makes privatization difficult both to achieve and sustain, and tends to result in extremely low privatization receipts. Within the group of ECA countries Poland and Hungary received significantly better privatization receipts than countries like Kazakhstan, Georgia, Moldova and Ukraine reflecting the level of interest taken in the commercialization of their utilities. Even privatization receipts per GWh of sales at the distribution level in Hungary and Poland appear to be low compared to the privatization receipts in Australia (7.4 times), UK (3.5 times) and Latin America (5.8 times).[12] Lithuania has substantially completed the commercialization phase and is fully poised to enter the competitive markets. It can afford to wait for the investment climate to improve, as it can raise the funds needed for urgent rehabilitation through internal cash generation and access the international debt markets because of its enhanced credit rating obtained through patient commercialization of its operations. Turkey is also approximately in the same position.

11. This is referred to as the "supply" function elsewhere in this report. Generally distribution wires function covers network operation and maintenance. The supply business comprises metering, billing and collection in relation to the retail consumers. Often the wires business may perform this function for a fee on behalf of the supply businesses.

12. Mangesh Hoskote, Privatization Strategies in Electricity Distribution. Presentation made on April 7, 1999 at the World Bank Energy Week, 1999.

CHAPTER 3

GETTING THE MARKET STRUCTURE RIGHT

Non-Discriminatory Approach

The approach of the multilateral and bilateral donors in the 1990s regarding market structure in ECA countries was based on the firm faith that unbundling the vertically integrated utilities, privatizing the unbundled entities and operating a competitive power pool was the best way to reform the sector. This approach was used irrespective of the size of the countries and their systems, levels of development, or the degree of chaos in the sector. Somewhat interestingly, the more chaotic the status of the power sector was, the more urgent the above type of reform was considered. Since in most of these countries nearly 100% of the population had access to electricity and the power systems had capacities in excess of the demand, it was assumed that they presented the conditions for quickly implementing the above type of reform. Experience of operations in these countries during the 1990s does not seem to validate this non-discriminatory approach of applying one standard market structure for all situations.

The core values to be promoted by all Bank operations are economy, efficiency, environmental soundness and elimination of poverty. Privatization and competition are the means to achieve these values. Privatization of the capital-intensive power sector is advocated to enable the governments to shed this commercial activity and focus on the more urgently needed human development and poverty elimination objectives. Unbundled structures provide the competitive framework to provide incentives for efficiency gains while the private sector is expected to maximize the effectiveness of competition. Further, the private sector functions more efficiently under competitive conditions. For the regulated monopoly components of the sector, incentives for efficiency gains are not as strong, but can be encouraged through incentive based regulation of the monopolistic environment. It is useful and necessary to distinguish between key values to be promoted and the means to achieve them. Thus for example in small countries with small power systems, where no meaningful competition is possible, vertical and horizontal unbundling of the sector into tiny entities with no economies of scale, in search of the elusive benefits of competition, does not make much sense. In such countries we have to look for simpler solutions on the basis of rational tradeoffs among the means, keeping a firm focus on the core values.

Approach to Small Systems

As a rule of thumb no single entity should operate more than 20% to 25% of the generation or distribution capacities to sustain a good competitive environment.[13] Thus if a system size of a country cannot accommodate 4 or 5 generating companies and 4 or 5 distribution utilities (or large customers with direct access), all with reasonable economies of scale, then it is time to think whether the strategy of unbundling and competition is appropriate for that country. In such countries alternative options to be considered would include:

- Privatizing the vertically integrated utility as a whole and regulating it;
- Splitting the vertically integrated utility into two or three vertically integrated regional utilities, privatizing and subjecting them to regulation; and
- Unbundling the existing utility into one generating utility, one distribution utility and one transmission and dispatch utility, privatizing generation and distribution, and retaining transmission and dispatch in the public sector, if needed. All three would be subject to regulation.

In small countries heavily dependent on imported electricity, as appears to be the case in Albania, the last alternative may be relevant. In Moldova something similar was done, though the fragmentation of the small distribution system into five tiny entities with poor economies of scale is difficult to understand. In Tajikistan, the Bank and IFC, in a novel experiment, has recently promoted and financed a small NGO owned vertically integrated utility operation,[14] on the basis of a long-term concession, in the remote and poor area of Gorno Badakshan. Under the circumstances of the country and the area, this is considered a reasonable solution.

In small countries, with no ambition to join the EU, and with a power system of smaller than 3,000 MW, one should be wary of advocating vertical and horizontal sector unbundling and introducing competitive pools, especially when their system operation is not integrated in any way with, any international system. Such a reform would increase transaction costs and is unlikely to result in any meaningful competition. These increased costs should be weighed against the expected improvements in corporate governance from increased transparency of their accounts. However, opportunities for competition arising from cross border supplies or demand should not be lost sight of. If the small systems are well-interconnected to the adjoining grids and form part of any international network, a simple vertical splitting of generation, transmission (including dispatch) and distribution, provision of non discriminatory third party access to the transmission and distribution system at least for the large consumers and distribution utility with freedom to import electricity from abroad, could bring in competitive benefits, and make domestic generation more efficient.

Fragmentation of Distribution Systems

Many ECA countries have a tendency to fragment their distribution systems into tiny entities with no economies of scale, presumably for the purpose of making the franchise area coterminous with the jurisdictions of local administrations. Thus during 1994–95, Georgia created 66 to 70 distribution utilities (to handle 1.7 million consumers and sales of 7 TWh) and municipalized them with undesirable consequences. They had later to be regrouped into 10 regional companies and even this was found to be too many and too uneconomic and small in the context of privatization. Further reduction of the 9 non-privatized distribution entities into one or two is being considered. Similarly

13. It is also important to remember that such competition from four or five generating companies should be available not only for meeting the base load, but also the intermediate and peak loads, in effect, covering the whole load curve.

14. This utility will have a generating capacity of about 30 MW and serve 250,000 consumers with an annual sale of about 137 GWh.

in 1997, Albania had 33 distribution entities to handle sales of about 5 TWh. Armenia regrouped its 70 distribution entities into 11 larger ones. Bulgaria reduced them from 28 to 15 and Lithuania from 7 to 2. Still even the enlarged distribution entities were not large enough to attract private sector interest, because of their small and uneconomic size. Further reduction in number is being contemplated. Moldova split its tiny system into 5 distribution entities to enable competition, but they were too small to be economic by themselves. Union Finosa acquired three contiguous ones and the others have not attracted investor attention. The lesson emerging from the experience related to this aspect is that distribution systems must have economies of scale and should not be artificially split into tiny entities in the hope of enabling competition. Many believe that the minimum size of an economic distribution entity should be such that it serves a minimum of about a million consumers and handle total sales of the order of at least 2 TWh. Also the split should ensure that all resulting entities have a reasonable mix of urban areas with dense load and rural areas of scattered load and have comparable sales volumes. This is necessary to avoid "cherry picking" by investors. Otherwise the investors would pick only the profitable urban segments (as was the case in Georgia, Moldova and Kazakhstan) and leave the unprofitable rural segments to be handled by the public sector.

Single Buyer Model

A market structure based on a single buyer model had been adopted in Hungary, Poland and other countries as an interim measure before moving into a fully competitive pool providing a choice of supplier to all consumers. Under this model, the state owned transmission and dispatch company buys power from generating companies on the basis of long term and short term power purchase agreements (PPAs) negotiated with each producer and sells electricity at one single pooled average wholesale price[15] to all distribution utilities and the large consumers eligible to buy directly from the wholesale market. The retail price for end consumers is regulated on the basis of adding a distribution charge to the wholesale price. Long term PPAs (generally 10 years or more) and short term PPAs (one year or less) are covered by "take or pay" provisions guaranteed by the state. The market risk is thus fully transferred from the generators to the single buyer, who is obliged to pay the generator for the power not purchased when the demand declines. Thus during periods when demand lags behind contracted quantities, the average wholesale price per kWh tends to rise, which necessitates the upward revision of retail tariffs. The wholesale price may also rise on account of other reasons such as increased fuel prices, exchange rate variations, etc. for which the prices in PPAs are usually indexed.

Governments are often reluctant to support upward revisions of retail tariffs, and when retail tariffs are not raised correspondingly or in time, the financial viability of the state owned single buyer is eroded, as the generator gets his guaranteed contract price and as the distributor gets his guaranteed margin. Often the single buyer is compelled to buy power at high prices and sell it at lower prices. Hungary represents the most prominent example of this kind of situation. The government is reluctant to allow the retail prices to rise to the full extent, compels the single buyer to reduce wholesale prices and compensates the single buyer through direct budget subsidies. Apart from being the object of such abuse, the single buyer model also makes it difficult to move towards the competitive market model. The rigidities associated with the PPAs with their guaranteed "take or pay" provisions create significant stranded costs when the market moves to a competitive model and makes such a move difficult and unpalatable to the consumers, as the stranded costs are recovered from consumers as a surcharge to the regular tariff. Thus though it is easier to implement, the single buyer model is not considered as a good interim step for moving towards the competitive model. Some of the options adopted in various parts of the world to integrate the IPPs into the emerging wholesale power markets have been reviewed by Fiona Woolf and Jonathan Halpern in World Bank Working Paper No. 2703 of November 2001.

15. It includes pooled average generation prices and transmission charge.

Other Wholesale Market Models

Countries such as Russia (and Georgia recently) operate wholesale markets on a slightly different basis. There is no direct contractual link between the generators and distributors. Generators supply to the wholesale market at regulated prices and the wholesale market supplies the distribution utilities at the pooled average wholesale market prices. This kind of arrangement lends itself to different kinds of abuses. When the demand is well below available capacity, the wholesale market can be pressured to allocate demand arbitrarily to favored generators such as the coal-fired plants (based on the strong lobby of the miners). It can also be pressured to allocate the low demand to all generators to ensure that every plant is kept working and employment in the plants is sustained. This leads to partial loading of the thermal plants resulting in poor efficiency and higher fuel consumption. These practices distort least cost dispatch. Further, in an environment of extensive non-payment, the wholesale market is unable to collect dues from the distribution utilities and settle the dues of the generating companies. The wholesale market has also been known to link distributors to generators arbitrarily for purposes of payment. In an atmosphere of non-payment and selective payment, such arbitrariness can lead to corrupt practices. There seems to be a clear need to allow direct bilateral contracting and settlement between the distribution utilities and the generators, especially when the payment discipline is not fully restored.[16]

Power Pools

A competitive power pool based market model does not suffer from such problems, but, by and large, does not seem to fit in, at this stage, with the ethos and the evolution of markets in most ECA countries. Many countries seem to be reluctant to provide nondiscriminatory or even regulated third party access to their wires services, even to large consumers. Even in Poland such access is not available for import of power from abroad. In Hungary such access is available only if the buyer buys at least 50% of his annual needs from domestic suppliers. Ukraine clearly demonstrates the futility of introducing this sophisticated model in an environment of extensive non-payment and serious reluctance on the part of the government to let the retail prices move up or down in tandem with the movements in the wholesale market or pool prices. When retail prices were not allowed to be raised, the regulator was forced to declare an 'emergency' and allow arbitrary downward correction to the hourly marginal price in the pool in order to sustain the low retail prices. In any case the wholesale market could not simply collect dues from the distributors and settle the dues of generators. In effect the Ukrainian competitive pool never functioned in the way it was intended to, because of the premature application of this model.

By and large, a dispatch based mostly on bilateral contracts between the generators on the one hand and distributors and large consumers on the other hand and the pool mechanism coming into play only for the residual real time balancing of demand and supply (called balancing pool) would appear to be the practical and preferred option in most FSU countries, where payment discipline is still uncertain. Settlement for the contracted power would also be bilateral and only the value of the power sold for the balancing pool would pass through the wholesale market settlement procedures and be subject payment risk. Kazakhstan operates a pool somewhat on these lines and cuts off non-paying distribution utilities and also cuts off consumption in excess of the contracted quantities.

Capacity Additions

Capacity addition is not a major issue in most of these countries as the present capacity is in excess of demand. However, it is relevant for Hungary, Poland, Turkey, and the Balkans and would be relevant for some parts of Russia in the next few years. While the government agencies or even the transmission and distribution utilities could be involved in preparing medium and long term load

16. An important proviso to this is that both the generating and distribution companies should be privatized entities. Otherwise collusive contracts are known to be made at low prices to deprive the state owned generating units of their normal revenue.

forecasts and could indicate the need for the new capacity and the desirable part of the grid where such new units should be sited, it is best to leave the investment decision itself to the market. Concepts advocated in Hungary that the regulator (HEO) would determine the new capacity needs and have them commissioned on the basis of competitive bidding are not in line with market operation.

Clarity of Objectives

In the sector reform plans of any given country, there should be a clear choice as to whether competition is the overriding objective or whether ease of privatization is the preferred objective. If competition is the objective, privatization becomes somewhat more difficult as there must be constant post privatization vigilance needed to prevent the privatized utilities from anti-competitive behavior, through holdings, acquisitions and mergers. Cross ownership between generating and distributing companies (especially when the wires business and supply business is bundled together) has to be prohibited from the beginning and guarded against after privatization. When distribution is unbundled into supply and wires business, some cross ownership between generation and supply business may be tolerable as seen from the example in UK. In a competitive model of this kind the generating plants have to take full market risk and distributing utilities have to face the risk of uncertain supplies. Under such conditions it is more difficult for the investors to access long term debt at reasonable costs and therefore privatization becomes somewhat more difficult. Even in USA, the investors in such merchant generation plants are unable to access long-term funds on account of the market risk and price risk and have generally chosen to borrow funds with 5-year maturities with bullet payment at the end (called "mini-perms" in the trade). At the end of 5 years, they may be converted into long-term loans or simply rolled over for another 5 years at revised prices, based on the first 5 years track record.

If ease of privatization is the main aim and competition is not that important, then structures which correspond to vertically integrated utility operation in the given franchise areas or combinations of generation and distribution facilities in the same area are needed. This approach would reduce greatly the type of risks associated with merchant plants and may attract greater investor interest, as they can access long-term debts with relative ease. Lack of clarity of this kind of choice has resulted in difficulties in Georgia and Kazakhstan, where, despite announced interest in competition, some investors have been allowed to acquire generation and distribution facilities in the same areas. Had these areas been privatized on a clearer basis, the privatization may have been faster and privatization receipts greater.

Likely Structures

In most of the countries desiring to join the EU, the structure is likely to be one of coexistence of regulated and liberalized markets. The sector would be unbundled into generation, transmission, and distribution. Non-discriminatory third party access to wires services would be provided on a regulated basis at least to the large consumers. Thus the large consumers (often referred to as 'eligible' consumers) could choose their supplier, while the others (referred to as captive consumers) could buy only from their area distribution utility. The tariffs for the latter would be regulated and the retail tariff would be a sum of generation, transmission and distribution costs. The eligible consumers would be buying at negotiated prices taking the price risk. Over a period of time the share of the eligible consumers in the total number of consumers would rise and the share of captive consumers would fall. The EU member countries are expected to reach full liberalization or choice for 100% of their consumers no later than 2010.

In the light of the experience in California, many governments are afraid of immediate and full liberalization of the market and total reliance on such a market. Competition, while generally conducive to lowering of prices, could very well lead to high prices and price volatility. Hence the preference is for the coexistence of regulated and liberalized markets while the markets mature. Such a gradual approach to market liberalization is advocated by the Bank in its review of the California Power Crisis (see Besant-Jones and Tenenbaum, 2001).

CHAPTER 4

PRIVATE SECTOR PARTICIPATION

Privatization to Follow Commercialization

The clear lesson emerging from the experience in the ECA countries is that when privatization follows substantial commercialization of the sector on the basis of an appropriate market structure, it attracts considerable investor interest. When privatization is carried out following transparent competitive procedures, privatization receipts are maximized. Poland, Hungary and to some extent Moldova are good examples. Haphazard and arbitrary privatization by direct negotiation ahead of commercialization and on the basis of unpractical market structures results in poor privatization receipts, chaotic market conditions and in no palpable improvement of the sector and can lead to disinvestments by disenchanted investors. Ukraine, Kazakhstan and Georgia provide the examples for this proposition in varying degrees.

The Independent Power Producers

The earliest private sector entry into the power sector of many developing countries was in the form of independent power producers (IPPs). Investors were invited to set up new generating capacities and sell the electricity generated to the state owned utility on the basis of a "take or pay" contract guaranteed by the state. The investor was thus insulated against demand risk, dispatch risk, price risk, and exchange rate risk. Despite this, in early IPP contracts concluded on the basis of direct negotiations, the electricity prices tended to be significantly higher than the average cost of generation of the utility[17] and the contracts themselves appeared to be inequitably weighted in favor of the investor. Since most such contracts were for a long duration (15 to 20 years), it was difficult to accommodate them when the countries wanted to move towards competitive market models. Reneging from the contracts was not an option and the investor had no incentive to assume the role of a merchant generator. The difference between the market price and the IPP contract price became a stranded cost to be recovered from the consumers through a surcharge on

17. The difference in prices was often a function of the perceived country risk.

tariffs. In many countries, negotiated IPP contracts offered scope for political corruption. Many countries tended to contract for substantially higher capacities than what was warranted even by the most optimistic of demand forecasts, resulting often in the utility having to pay for power, which the system could not absorb.

Hungary, Poland and, to a greater degree, Turkey resorted to this option. In Hungary and Poland IPP contracts are causing stranded cost problems and the countries are trying to work out suitable solutions. In Turkey the IPPs had a share of 25% of the total generation and seriously eroded the financial viability of the state owned generating and transmission company. These cases make it clear that the use of this mechanism requires a high degree of caution, discipline and reticence on the part of the governments. Capacities to be contracted have to be determined on the basis of conservative load forecasts and such capacities should not exceed a small percentage of the total capacity needs of the system. Through transparent international competitive bidding, reasonable prices close to the average cost of the utility generated power should be obtained. The contract should allocate risks equitably between the two parties and government guarantees limited only to the value equivalent to the debt financing for investments and should decrease as the debt is retired. Utilities should hedge against the foreign exchange risk where feasible. IPPs thus contracted may not present a serious problem at the time of introducing competitive models. The advantage of this option is that investors would be able to raise long-term debts on reasonable terms on the basis of the guaranteed cash flow.

Transfer of Operating Rights

Turkey also attempted to give existing state owned generating units and distribution areas on long term leases called Transfer of Operating Rights (TOORs) to private investors, in view of the constitutional court ruling prohibiting their outright sale to the private sector. These leases were to be offered for a substantial upfront fee, determined by competitive bidding. Twenty-five distribution areas and twelve generating units were thus offered. Many of the lessees were unable to raise the funds needed to pay the upfront fee. Before the transactions could be finalized, the government was able to have the constitution amended and a special law passed to enable restructuring and privatization of power sector assets. Thus most of the lease transactions are not expected to be finalized. These lease agreements do not appear to have dealt with the issue of efficiency improvements and new investments satisfactorily. Though Turkey has not pursued it, with suitable improvements it may still be a practical option in countries where there is legal or social resistance for the outright sale of the power facilities.

Majority or Minority Shares?

The practice of direct issue of 15% to 25% of the shares to managers and employees of the utility and the sale of another 10% to 15% of the shares to the public through stock exchange was followed in Ukraine, and, with some variations, in Russia and other FSU states. This approach had assumed that it is good for the staff morale and the growth of the stock markets and was required to gain political support. However, it did not prove beneficial to the utilities in most countries. In most cases shares to staff were issued against privatization vouchers and compensation vouchers and not against cash. Further it led to "insider control" of the utility and its operation, more for the short-term benefit of the employees than for the good of the utility or its consumers, and greatly exacerbated the non-payment and barter problem and the corrupt practices associated with them. These schemes did not result in any better or healthier management of the utility. In this context when minority shares were offered to the investors, it did not attract serious strategic investors. Those who took the minority shares quickly acquired 25% plus one of the shares, by purchasing additional shares from the staff and other individuals. This level of shareholding was enough to prevent the company from undertaking any meaningful reform and to scare the serious investors away, when the remaining shares were offered for privatization. In Russia, 49% of the shares in the apex national power company RAO UES were privately held mostly by institutional

investors. Of this about 30% was from foreign investors. Similarly in the regional electricity companies, 49% of the shares were held by RAO UES and the rest by institutional and individual investors. In both cases this kind of widespread private shareholding did not lead to any strong management. Reasonable management at the levels of RAO UES and some of the regional entities was often secured *in spite of such shareholding largely through the initiative of the reformers in the government.* The minority private shareholding (which was the result of premature and partial privatization) is believed by most observers to have been an impediment to speedier reform of the sector towards market models. This reinforces the well-known wisdom that sector and institutional restructuring must precede privatization, as it is more difficult, costly and time consuming to restructure privately owned utilities than the state owned utilities.

Negotiated direct private sales in Kazakhstan were quick and saved time, but privatization receipts were ridiculously low, and investor interest could not be sustained in the absence of a functioning market structure and reliable regulation. Experience in Estonia relating to the privatization of the two generating units Narva Power Company (300 MW) through prolonged direct negotiation with NRG of USA showed that direct negotiations do not even save time. In general, negotiated direct sale of state owned assets to the private investors is vulnerable to corrupt practices and is not considered an advisable option, under most circumstances.

Under the legal traditions and circumstances prevailing in these countries, it is prudent to offer a minimum of 51% and preferably enough to avoid the blocking of prudent decisions by minority shareholders.[18] The aim is to enable the investor to have clear management control and the run the utility unhampered by unhealthy pressures by minority shareholders. Privatization done in recent rounds in Ukraine on this basis met with reasonable success. Russian proposals for the future privatization envisage the holding of 25% plus one of the shares in most companies by RAO UES. Given the need for the states to maximize the privatization receipts, it may be appropriate for the governments to consider selling all shares and retaining only a golden share (as was done in UK and several West European countries) which gives the right for the government to approve changes in the capital structure, business profile, acquisition and mergers and dissolution. Alternatively a well-prepared shareholders agreement giving this right to the government would also be an acceptable mechanism, in the context of the need to promote competition and to discourage anticompetitive behavior.

Antitrust regulation and enforcement mechanisms are new and ineffective in these countries and there is a real need to restrain the privatized utilities from engaging in anticompetitive practices through price fixing cartels, holdings, acquisition, and mergers. Cross ownership among generation and distribution has to be controlled and for all these purposes the use of golden share or the shareholder agreement may be a practical solution. A recent ruling by the Court of Justice of the European Commission lays down that the use of golden share for general and strategic purposes, based on previously announced precise criteria and subject to review by courts could be lawful.[19] The Governments therefore should use a great deal of restraint in the use of the golden share and use it exclusively for public purpose. It may also be useful to limit the use of this share for only a period of ten years or less till antitrust legislation could take roots in the country.

Prevention of Resale and Arbitration

In Ukraine respectable financial investors acquired the distribution assets offered in the earlier rounds and quickly transferred them to undesirable offshore companies, which would not have qualified in the first instance. A golden share could come in handy in such instances. Based on this experience, it may be prudent to stipulate in the privatization contracts that the assets should not

18. In most FSU states, 25% plus one share enables one to block major changes proposed by management. Thus in effect the strategic investor needs to have 75% plus one share to avoid such blocking.

19. Press Release of the Court of Justice dated 4 June 2002 re: the use of golden shares in Portugal, France and Belgium.

be resold for, say, five to seven years to any other party with qualifications less than the original investor. Otherwise, the elaborate pre-qualification exercise would be meaningless.

Most investors are jittery about investing in emerging markets relying solely on the local judicial system to resolve their disputes with the state. In Turkey headway could be made only after the constitutional amendment enabling international arbitration in a neutral venue. Widespread adoption of this mechanism is likely to improve investor interest and confidence. Specific provisions enabling appeals to a Special Appellate Tribunal had also been found to be a helpful mechanism in Latin America, India, and the USA.

Privatization of Generating Units

Privatization of generating units calls for a clear enunciation of the structure and rules of the market. Privatization had been somewhat easier in countries with a single buyer model, with government guaranteed IPP type of contracts. In countries which desire to move to competitive pools, the generating units will have the role of merchant plants taking the demand risk, dispatch risk and price risk. In such cases, the need for clear market rules and enforceable payment discipline is paramount, to attract investors and enable them to raise finance. Investors in merchant plants facing such risks find it difficult to raise long-term finance at reasonable terms. In USA, 80 GW of such merchant plants had to be built in the last three years based on expensive debts ($30 billion to $50 billion) of five year maturity with bullet payments at the end and they are all finding it difficult to convert them into long term debts on account of excess capacity, declining demand, low wholesale market prices and low valuation of their equities.[20]

In Kazakhstan and Georgia, investors (Tractabel and AES and National Power and Ormat) who had already acquired distribution systems, were keen to acquire the associated generation assets to ensure that they get reliable supplies. In the absence of clear market rules and payment discipline even these arrangements did not work well. Tractabel disinvested from Kazakhstan and AES faced problems in Georgia arising from payment discipline. While they paid in full for the power they got from the grid, they did not get paid in full for the power that their generating units supplied to the grid.

Privatization of generation could be somewhat easier in countries where the generating units could directly enter into supply contracts with the distribution utilities and large consumers and where system dispatch supports such bilateral contracts and only residually on the basis of balancing pools. The operation of the grid becomes difficult when the generators decide to stop generation when the buyer fails to pay. Often the system has no facilities to handle such contingencies leading to system instability. Nonetheless, Kazakhstan, Georgia and Ukraine (to some extent) developed procedures to cut off supplies to such defaulting buyers without affecting the system stability too much.

Experience in Poland, Hungary and Ukraine indicates that saddling the generation units with the ownership of associated coal or lignite mines and or saddling them with the obligation to use the allocated fuel (bowing to the pressures of coal mining lobby) are counterproductive and reduce investor interest. The investors prefer to have freedom of use of fuels of their choice, especially in competitive markets. When generation is subject to price regulation, investors prefer to have their own choice of fuel subject only to the consideration of prudent prices and subject to the tariffs allowing the full pass through of such prudently incurred fuel costs.

Privatization of Distribution

In respect of distribution privatization, it is a good practice to sort out (before commencing privatization) the issues relating to the "right of way" for network lines and facilities located in lands

20. See Refinancing Risk in the Power Sector-The Preponderance of "Mini-Perm" Debt, Standard and Poor's Utility Perspectives, 9 September 2002, available at http://www.standardandpoors.com/ratingsdirect.

owned by the state and the local or municipal governments. In addition, the issues relating to the quenching of any inherent or implicit legal rights such governments may have (in the legal tradition of these countries) over the local network facilities, through the amendment of all related local laws must be addressed in advance of privatization. Otherwise privatization of the network facilities fragmented into hundreds of components would be practically impossible. Alternatively, the investor may have to deal with numerous municipalities to perfect the title over his property and acquire operational rights. In Hungary recently the mayor of a small municipality decided to charge an exaggerated rent for all the distribution pole location with retrospective effect from the new owners of the utility. Fortunately the courts ruled such claim to be unlawful. Otherwise it would have landed the new owners of all distribution companies in potentially serious financial problem. In Romania the Bank had to press for the suspension of a newly enacted law by the parliament vesting the rights relating to electricity and gas networks with the municipal authorities, thus creating a problem in the planned privatization of the distribution utilities.

Based on the experience in several FSU countries, it is considered a good practice to ensure that a comprehensive inventory of all assets to be sold under the privatization contract is compiled on the basis of physical verification. Similar lists need to be compiled in respect of all payables and receivables and long term and short term debts and obligations, debt restructuring plans and agreements with creditors. All these aspects need to be certified by independent auditors. The point relating to the inventory of physical assets is specially important for distribution utilities in FSU countries,[21] which have the practice of assigning distribution feeders to resellers and not keeping track of the current status of all such feeders at the time of privatization. In many cases, the new owners had a difficult time in dealing with the resellers from feeders to which they were not entitled. The possibility of quenching the rights of all resellers in the area should be explored before attempting to privatize distribution to strategic investors.

Labor unions are very powerful in the ECA countries and their support is essential for any reform effort. Privatization in Hungary was facilitated by the government reaching clear agreements with the unions, before privatization, on labor concerns such as levels of employment, severance compensation for separated labor, allocation of funds for the separated labor, retraining needs, period of retention of managers subject to suitability etc. In Poland long delays in privatization were attributed to the lack of such prior agreements and the recalcitrance of labor unions during privatization negotiations.

Tariff principles, policies, formulae, and credibility of the regulatory bodies and implementation arrangements are the most important factors that make or break a privatization deal. Experience shows that embedding the principles, policies and even the formulae in the basic law provides greater comfort to investors, than when they are left to be worked out in the regulations to be issued by the regulatory body from time to time. Given the level of political development and the level of maturity of the regulatory bodies in these countries, their decisions are not easily predictable and occasionally tend to be arbitrary, based on political compulsions. In a recent Bank survey of power sector equity investors, 65% of the respondents considered the tariff level as the critical for the success or failure of their investments.[22] Given the unpredictability of political changes in many of these countries, embedding in the tariff formulae in the privatization contracts and the multiyear tariffs themselves have been advocated to insulate the investments from the uncertainties of the tariff risk. The recent long term concession for the Pamir Energy Company in Tajikistan for a vertically integrated utility operation as well as the leasing agreements for district heating in Lithuania incorporate such multiyear tariffs in the concession agreement and are considered good examples. Such a method may be more successful in attracting investors especially in the case of privatization of distribution utilities.

21. See John Huffaker, VP AES Silk Road, "An Open Letter to Emerging Market Regulators" in Power in Eastern Europe, Issue dated 10 December 2001.

22. Ranjit Lamech and Kazim Saeed, Private Power Investors in Developing Countries- Survey 2002-Preliminary Findings, Energy Forum 2002, World Bank

Concept of Strategic Investors

In order to meet the two key objectives of privatization of the utilities, the selected investor should have cash and access to debt financing to buy the assets and superior technical and managerial capability to operate the system with greater efficiency, profitability and on a sustainable long-term basis. From this point of view, the Bank and other donors have advocated competitive bidding among pre-qualified strategic investors. In practice there happens to be only a limited number of strategic equity investors in the power sector and most of them are from North America or Western Europe, as these regions have investors with cash and utility management experience. Recent attempts at privatizations in Armenia, Moldova, Georgia and several other FSU states did not evoke any response. As noted earlier most of the investors from North America seem to be facing problems of their own and appear to have lost interest in adding to their portfolio more risky power sector investments in the emerging markets. The time has come for the donor community to realize the basic limitations of the concept of strategic investors. It is not easy to imagine that all the power assets of large countries like Russia (216 GW) or that of the rest of the East European and FSU states could be privatized to a handful of conventional strategic investors from the west. Also many of the investors from Western Europe are affiliates of state owned utilities, and the concept of state owned utilities in ECA countries being privatized to the affiliates of state owned utilities of the West is somewhat troubling. There is a trend of acquisitions and mergers in Europe, which if left unchecked by the EU, is likely to result in Europe being dominated by a few immensely large utilities with little scope for meaningful competition.[23]

We need to think in terms of enlarging the pool of strategic investors and make special efforts to attract the attention of potential strategic investors also from Japan, Australia, China, parts of Asia, and Latin America. Second we need to take a fresh look at the interest shown by investors from Russia[24] in the sale of electricity assets in former FSU states. With suitable association from western utilities these investors could potentially be interesting, because of their local knowledge and familiarity with the host country's practices and lobby groups. So far Russian firms have been routinely eliminated during the pre-qualification stage, partly because of the discomfort of the host countries to invite the Russians back into their economies. Privatization of coal, oil and gas in Russia proceeded largely on the basis of local entrepreneurs acquiring the assets. The possibility of privatization *focused on local and regional entrepreneurs or financiers* (with appropriate technical or managerial cooperation agreements with qualified western utilities or their affiliates) purchasing the assets offered for sale, needs to be seriously examined. Similarly the bidding could be made open to *financiers all over the world*, so long as they form joint ventures or conclude technical collaboration agreements with modern well-run utilities or their affiliates. In the final analysis promoting domestic investors to work in close collaboration with foreign financiers and foreign utilities may provide the sustainable basis for the privatization efforts, especially in large countries. It is interesting to note that a recent OED review recommends that the World Bank Group should maximize the involvement of the local private sector.[25]

Equity for Debts Swap and Assets Stripping

The concept of allowing the creditor to acquire the assets in lieu of the debts owed to him needs to be looked very carefully and cautiously. Gazprom took over gas distribution in Moldova on such grounds and it did not result in any perceptible improvement of the performance of the gas utilities.

23. Atle Midttun (Ed), European Energy Industry Business Strategies, Elsivier Science Ltd., Oxford, UK., 2001

24. Many Russian investors are interested in the Ukrainian Distribution Utilities through which transmission lines with potential for Russian electricity exports to West Europe pass in the hope of earning substantial transit fees, in future.

25. Private Sector Development in the Electric Power Sector, A Joint OED/OEG/OEU Review of the World Bank Group's Assistance. August 2002 (Draft)

Also it appears to have promoted collusive asset stripping in Ukraine. The utility develops a large volume of debt, for example, to the fuel supplier and then allows the creditor to sue the utility and get a part of the assets (such as a generating unit) at ridiculously low prices in a collusive and unadvertised auction. This problem became so serious that the Ukrainian government was persuaded by donors to pass a law of moratorium on such debts to prevent such asset stripping.

Franchising and Management Contracts

It may also be worth the while to consider the possibility of such options as "franchising" and management contracts. In the hotel, tourism, fast food and a similar range of industries, the concept of franchising is widely practiced and very well known. The international hotel chains often take only a small minority share, but give the hotel their stamp of a well-known international brand through the standardized franchising arrangements, which ensure quality standards consistent with the brand name and its reputation. It may be worth the while for the Bank group to take the initiative of inviting some of the western utilities and their associates to explore how such franchising arrangements could be worked out, say, for the power distribution business.[26] Management contracts have been used in some African countries with mixed results. Georgia has recently given management contracts in respect of its non-privatized generation assets as well as the operation of its transmission and load dispatch system and the wholesale electricity market. The teething problems of the contracts are being sorted out now, and the general hope is that when the performance improves under the management contract, there would be greater investor interest in buying these assets. The management contractor himself may come forward to take equity position in the companies. Well-structured management contracts could be a useful interim solution, both to commercialize the utility and to wait out the current slump in the investment climate.

Commercialize and Wait for Better Investment Climate

The best insurance against the current slump in investment climate is to use the time to comprehensively commercialize the utility on the lines indicated in the earlier chapter, improve corporate governance, create and stabilize independent regulation, and improve the legal infrastructure. Once the utility operation has been improved to a level adequate to meet all its expenses, debt service requirements and produce an internally generated cash surplus needed to finance at least 25% to 30% of the urgently needed rehabilitation investments, and once it is able to access debt markets on the strength of its balance sheets and credit rating for the balance of funds, it can afford to wait till the investment climate improves. At that stage even privatization through local stock exchange would be appropriate, as it would by then have a good management and governance and can upgrade them through cooperation arrangements with other advanced utilities. Lithuania is a good example of this kind.

Treatment of Bank Loans and IDA Credits

The issue relating to the treatment of the Bank loans and IDA credits in the context of the privatization of the assets financed by such loans or credits is also worthy of note. The Bank does not seem to have any special policy on this aspect. The standard conservative position would be to require that such loans or credits be prepaid from the privatization proceeds. Often the investors are unwilling to acquire the assets unless the loans/credits are also transferred to them. Under such circumstances, the Bank may have to agree to this in order to facilitate privatization. When AES bought the Tbilsresi power plant in Georgia, loans and credits of all donors such as the Bank, IDA, EBRD, and KfW were transferred to AES. As the Bank loans and IDA credits have much longer maturity and much greater concessional element that commercial loans, extending these terms to

26. Zaheer, Salman and Dennis, Clarke. Power Privatization Prospects: Eastern Europe and Central Asia: Role of the World Bank Group. Presentation, 2001.

an investor like AES could amount to distorting the market. However, in most cases the concessional elements remain with the government and the relending to the utility is generally on near commercial terms (including the foreign exchange risk). In such cases the Bank could agree to such requests, subject to the condition that the Bank loans are relent to the investor on conditions not more liberal than in original on-lending/subsidiary loan agreement between the government and the utility.

Post-Privatization Phase

The responsibilities of the government do not cease upon privatization of the sector. They change, become different and often more complex. The government has to maintain stable sector policies and keep the letter and spirit of the privatization agreements it has signed and work jointly with the new owners to solve local problems as they arise. Fair and transparent mechanisms for dispute resolution needs to be maintained continuously. In particular, it should ensure the continued independence of the regulatory bodies and allow them to set tariffs in a professional manner with out any political interference at the federal and local levels. It should specially avoid taking actions against the spirit of the agreements reached with the investors. The recent action of Hungary to raise the wholesale tariff at a certain rate and the retail tariffs at a lower rate is not considered by the investor community as fair or proper.[27] Similarly the actions of the Ukrainian government in preventing and later staggering retail tariff adjustments contrary to the requirements in the privatization agreements cost the government credibility and could adversely affect further privatizations.[28] The foot dragging of the government of Kazakhstan in tariff adjustment was perhaps the cause of disinvestments by Tractabel. Both the governments of Georgia and Moldova did backtrack similarly on tariff issues. Recently the government of Moldova appears to have realized the advantages of keeping up its agreements and is cooperating better with the investors. In competitive systems the governments need to be constantly alert to the tendencies of the investors to indulge in anti-competitive moves.

27. See also "Confusion Grows Over Hungarian- Style Liberalization", Power in East Europe, Issue dated 23 November 2001 on the erosion in investor perceptions on the Government's approaches in Hungary.

28. "An Open Letter to Emerging Market Electricity Regulators", Power in East Europe, Issue dated 10 December 2001.

CHAPTER 5

SOCIAL SAFETY NET ISSUES

Concerns Relating to Employees

Power sector reform based on privatization and competitive markets involves complex social issues both from the point of view of the employees in the sector and from the point of view of the consuming public. The experience in ECA countries clearly highlights the paramount need to pay attention and be sensitive to both sets of concerns and plan developments accordingly.

Sector reform would result inevitably in the reduction of employment levels, both because there were too many employees to start with and because many of them are considered unsuitable for the tasks under private management. The problem of redundancy would generally apply to workers, while that of unsuitability would apply to managers. Careful planning is required to make the reduction reasonably phased, to retrain and relocate (where necessary) and find alternative employment for separated workers, and find resources for the severance compensation. Sorting out such issues ahead of the actual privatization through formal agreements with labor unions is known to attract investors and speed the process of negotiation. Hungary presents a good example in this respect. Its idea of setting apart a percentage of the privatization receipts for labor related compensations is a very sensible one in securing employee cooperation. Similarly the experience of the Bank in the coal sector restructuring of Russia provided a good example of socially sensitive reform package. On the other hand, the common practice in FSU countries of issuing shares to employees to secure their cooperation had generally been counterproductive and had not been helpful in furthering meaningful privatization.

Concerns Relating to Consumers

The concept of protecting the poor was not the common approach under centrally planned economies. Prices were kept low for the entire population by allowing tariffs for all residential consumers to be heavily cross-subsidized by industrial and commercial consumers. Further, there is a widespread practice in these countries of rewarding a wide range of people with utility tariff discounts[29] for acts of bravery, patriotism, or other great achievements. Such tariff discounts were also

29. This is also often referred to as “privileged tariffs”.

applicable to a wide range of victims of disaster (such as the Chernobyl melt down), war veterans, old age pensioners and others. In some countries such privileged tariffs applied to more than 50% of the population. In theory the federal or the regional government, which ordered the privileged tariff, was expected to compensate the utility for the loss. In practice, however, these compensations were not paid most of the time on account of budget constraints or paid in the form of offsets. These policies robbed the utilities of their legitimate (if low) revenues and did not benefit the poor, as the grant of privileged tariffs was not based on income levels or affordability. Such policies and procedures cannot be sustained in a reformed set up with private ownership of sector assets.

When power sector reforms are implemented, the overall tariff levels would rise to reflect the full cost of supply including the cost of capital. The structure of tariffs would change to reflect the actual cost of supply at different voltages. Thus the tariffs for residential consumers (who get supplies at low voltage) would be substantially higher than the tariffs for large industrial consumers (who get supplies at 11 kV and above). Such changes in levels and structure of tariffs would create resentment among residential consumers against reform, but, more importantly, would hit the poorer sections of the population very hard. By and large the general public would prefer a stable and reliable power supply at higher costs than a poor quality supply with frequent load shedding and supply interruptions; and public support could be secured through improved sector performance and public relations campaigns. The more successful programs have been gradual, announcing a schedule for the proposed changes to take place over a reasonable period of time, and implementing the changes as announced.

Tariff reforms in the FSU countries is further complicated by the climatic conditions in which people live, the legacy of high levels of service for the entire population at highly subsidized prices, and the public sense of entitlement for such continued service. People in these countries are worse off compared to those at the same income level in other regions, because of the additional expenditures they have to incur for heat and electricity to survive during the long and cold winter every year. This is further compounded by a stock of housing and heating infrastructure designed under conditions when energy was virtually free. Even though the current tariffs are low and inadequate to cover costs, they have risen during the decade in local currency terms by about 200% and have become a significant component of household expenditure. A rapid revision of tariffs to cost recovery levels and removal of cross subsidies would greatly exacerbate the situation to the poorer segments of the population, especially in the context of the rise in incomes not being able to keep pace with the rise in prices. Too rapid a price reform may also have adverse environmental consequence by forcing the poor to resort to the use of dirtier substitutes such as coal and wood. Thus price reform has to be gradual and needs to be carried out at a pace not excessively faster than the rise in household incomes, with a clear focus on protecting the clearly targeted poorer segments of the population.[30]

Social Protection Measures

Protection of the poorer sections of the public must receive special attention, planning and execution. The first step is to abolish the practice of privileged tariff completely. Despite agreements to this effect by various governments, vestiges of this practice still continue in many FSU countries and still remain to be eliminated. Second, through independent and reliable household income surveys, the poverty group to be protected (targeted poverty group) must be clearly identified. Third, such surveys should also identify the minimum levels of electricity consumption needed by such families and the levels of tariff they can afford for such consumption.

If the targeted poverty group and their total consumption are relatively small (say less than 1% to 2% of the total consumption of all consumers of the utility), then a lifeline tariff rate could be pro-

30. For a fuller and more nuanced discussion of these issues see Julian A. Lampietti et ale, *Social and Environmental Impact of Energy Reform in Europe and Central Asia*, a forthcoming Regional Study of the World Bank.

vided for the minimum monthly consumption needed by such families (say 150 kWh per month). The difference between the normal tariff and the lifeline tariff, in such cases, could be cross subsidized by the tariff for all other consumers. This is clearly a sub-optimal solution, but tolerable if the extent of cross subsidy is small and nearly 100% of the population has access to electricity. This kind of a social obligation must be clearly spelt out in the orders to be issued by the regulator. This method is widely practiced in many countries, at various stages of reform.

Another variation of this option, conceptually somewhat sounder, though still sub-optimal, is not to allow the other consumers to cross subsidize the lifeline rate, but to oblige the government to compensate the utility directly for its loss of income (as certified by the regulator) caused by the adoption of lifeline rates. Experience suggests that governments never properly pay such compensation amounts to the utilities either fully or promptly. The utilities are also known to exaggerate their claims in this regard. Variations of this method include the issue of electricity or energy vouchers to the targeted poor families, who pay their utility bills using the vouchers. The utilities exchange the collected vouchers for cash in the state treasury. Such a means-tested energy voucher system was used successfully in Bulgaria. In the context of rising electricity prices in 1997, the government of Hungary set up a Social Compensation Fund of HUF 1.5 billion with a contribution of HUF 1.0 billion from its own tax revenues and HUF 0.5 billion from the somewhat reluctant privatized distribution utilities and the state owned MVM Rt. This fund was used to compensate annually about 380,000 vulnerable households for their additional expenses on electricity consumption to the extent of about HUF 1,700 to HUF 12,000 per household. For 1998, the size of this fund was HUF 800 million contributed equally by the Government and the above utilities. These arrangements were considered temporary till the evolution and adoption of lifeline rates in the near future. Georgia and Moldova are considering lifeline tariffs. In Serbia, tariffs were raised in the first stage for the larger consumers and in the second stage the tariffs of the smaller consumers were raised to catch up with the former, in an attempt to soften the impact on the smaller consumers. Another variation of this concept is to charge enhanced tariffs only in the areas with uninterrupted 24 hour supply, and lower rates in areas with a poorer quality of supply.

In the case of Pamir Energy Company (of Tajikistan), serving one of the poorest regions of the country, the specific arrangements made to protect the targeted poor consumers is worthy of note. The funds needed by the government to provide agreed subsidy to the identified poverty group was funded by: (a) the income the government gets by re-lending IDA credit to Pamir Energy Company on commercial terms; and (b) a $5 million grant from the Swiss government. These amounts were specifically earmarked for this purpose.

A conceptually sound and optimal method of subsidizing the poorer households is for the government to provide direct cash income supplements to such families through increased social security payments or other similar payment system. Such subsidies would be needed for electricity (all through the year) and heat (during winter) and other utilities. Romania announces, at the beginning of each winter, the extent of subsidies for heat for the lifeline rated consumption of heat and provides funds in its budget. Income supplements designed to cover the cost of minimum energy and other utility bills of targeted poverty groups provided through social security arrangements is widely believed to be most sensible option. The Bank has been encouraging such arrangements through its adjustment lending operations and should continue to do so. Attention to this aspect is vital to lessen public resentment and build social support for reform. In order to achieve successful privatization of the power sector, the tariff reform with a clear focus on the social protection of the poor is an essential prerequisite.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

Conclusions

Overall during the 1990s, it would appear that the donor community may have pressed the privatization agenda somewhat ahead of abatement of the economic turmoil, proper stabilization of the economies, and the severe non-payment and non-cash payment problems caused by macroeconomic factors.

The privatization agenda, involving sector unbundling and introduction of competitive markets, appears to have been encouraged substantially ahead of the much needed comprehensive commercialization of the sector, tariff reform, social safety net reform and the stabilization of the functioning of the newly created regulatory and other bodies responsible for oversight.

The urgency of privatization has sometimes proceeded at a substantial cost of low privatization receipts. The introduction of sophisticated competitive pool type of market structure, regardless of the size of the systems, scope for competition, level of political development, and institutional maturity often appears to have been premature in many cases.

The willingness and ability of the strategic investors to absorb all the risks and rush to buy the assets offered for sale has been overestimated.

The speed or the slow pace of reform in various countries may, among other things, and at least to a small extent, be a function of the extent of correctness of these judgments.

As in general economic development, there are clear stages of development of the electricity sector. In the basic stage, the utilities are state owned and operate as government departments with no commercial focus. In the second stage, they become commercially viable and socially responsible public sector companies operating fully on commercial lines, covering their cost of supply (including the cost of capital) and generating enough internal resources to finance a part of their investment needs, borrowing the rest from the debt markets. In the third stage, they become privately owned competitive entities. An important lesson from ECA countries in the 1990s is that attempts at leapfrogging from the basic to the ultimate stage do not appear to have had much success.

At the end of a decade of operations, the priorities are becoming clearer. Focus on comprehensive commercialization, tariff reform, social protection reforms, legal reforms and a reliable and fair regulatory mechanism must precede emphasis on sector restructuring and privatization. A more

discriminatory approach for each country based on its circumstances should be used if we desire to carry out successful privatization of the sector.

Recommendations

Reform packages must be tailored for the circumstances of each country, as no single model would fit all countries. Within this framework, it is possible to make a distinction between the countries, which are planning to join the EU and others. The EU accession countries have a more appropriate legal infrastructure, a better understanding of the concept of property rights and are more exposed to the market mechanisms than the other countries. They have growing economies, solved their non-payment problem, and made substantial progress in terms of tariffs, social protection, and commercialization of their power sector. As a preparation for their EU accession they have made substantial progress in sector reform and attracting private investment. Pending their formal accession, they have to pursue their sector liberalization policies. Other countries are in a very different situation. Thus the approaches for these two groups of countries would be different.

For the EU Accession Countries

For the countries desiring to join the EU, the focus should be on unbundling of the sector and tariffs, regulated third party access to the transmission and distribution wires services, freedom at least for the large industrial consumers to choose their supplier from within the country or from abroad and on retail tariffs which fully covers the cost of supply.[31] Under these circumstances it may be sensible and advantageous to push through the privatization agenda and privatize generation and distribution entities to enable meaningful domestic and foreign competition.

For Other Countries

For the other countries, focus should be first on full commercialization of the sector using the window of the present unhappy investment climate, and choice of a market structure appropriate for the country's circumstances, and attempt to privatize when the investment climate improves.

For the Bank

For the Bank it may be necessary to focus on full commercialization of the utilities through a combination of adjustment and direct investment lending, complemented by non-lending operations in many of these countries. Also it is good to realize that sector reform is a long haul process lasting over a decade (unbundling - two-three years, market design and operation - two-three years, privatization - two-three years, regulatory reform – two-three years) and provide for the Bank's continuous involvement in the sector through appropriate instruments such as SECALs, programmatic lending, technical assistance, and sector studies. Equally important is to ensure some sort of continuity of Bank staff dealing with each country and improve institutional memory.

The Bank may also have to monitor the performance of the privatized utilities for a few years at least to learn whether the expected efficiency improvements are being realized or not. If not, the causes need to be identified for improvement of future operations and for initiating corrective steps. The cost effective mechanisms for this would have to be identified. To the extent IFC, MIGA and EBRD are involved in the privatization, perhaps the Bank could make use of their supervision and evaluation database for this purpose.

As noted elsewhere in this report, the core values of the Bank operations is economy, efficiency, environmental soundness and elimination of poverty. Unbundling, privatizing and introduction of competition are only the "means" to achieve these core values, and should not be mistaken as the "ends". Where these means prove inappropriate, the Bank should not be reluctant to search for other means to achieve the ends. The Bank's organization and its operational philosophy need to be informed by these pragmatic concerns.

31. Poland does not allow imports and Hungary allows only to the extent of 50% of the importer's annual consumption.

Case Studies

GEORGIA

Introduction

With a well-educated population of about 5 million and an area of about 70,000 square kilometers, Georgia was a wealthy member of the former Soviet Union (FSU). Following the collapse of Soviet Union, it had an extended civil strife caused by the separatist groups of the Abkazia and South Ossetia (A and SO) regions, resulting in the shrinkage of the economy till 1995. GDP growth resumed in 1995 and inflation was brought under control to the single digit levels. Resumption of security problems and the Russian economic crisis of 1998 adversely affected the economic recovery; and growth rates, since then, have been modest. Year 2000 was marked by a significant lack of rain affecting agriculture and hydropower generation, the key drivers of growth in Georgia. GDP growth in 2001 was about 4% and for 2002 a growth rate of 3.5% is forecast. The per capita GDP in Georgia was estimated at around US$630 in 2001.

Georgia's fossil fuel reserves and production are modest, and it depends almost entirely on imports of oil and gas from Russia to meet its energy needs. Despite having a nominal generating capacity far in excess of its low and stagnant demand, it also imports electricity, mainly from Russia and Armenia. Payment delays and defaults for these imports have often led to the interruption of supplies. Recently Georgia signed an agreement with Azerbaijan to enable the latter to export its natural gas using pipelines[32] passing through Georgia. In terms of this agreement, Georgia would be entitled to get 5% of the gas passing through as transit fees and also have the right to buy natural gas from Azerbaijan for a period of 20 years from 2004 at an annual rate of 500 million cubic meters and at a price of US$55 per 1000 cubic meters.

Power System Dimensions and Characteristics

The power system of Georgia, along with those of Armenia and Azerbaijan, was a part of the Trans Caucasian Interconnected power system- one of the 11 such systems in FSU. It was optimized as a

32. To be constructed and operated by Gruzrosprom, a joint venture company between Gazprom of Russia and Georgia International Gas corporation. The latter has 51% shares in the company.

part of that system serving FSU, and not as a system serving Georgia. With the dissolution of FSU, the systems of the three countries are operated as isolated systems, though there is still a common regional dispatching center (at Pontoel near Tbilisi), which for all practical purposes is defunct. Georgian power system is thus sub optimal and unbalanced to meet the national needs.

Generation Capacity

In 1997, it was reported that the nominal generating capacity of Georgia was 5,090 MW, consisting of 2,088 MW of thermal power stations (TPPs) and 2,843 MW of hydropower stations (HPPs), 5.4 MW of diesel generating sets and 153 MW of captive generating units of some industries.[33] The largest TPP is at Gardabani and it has 3 units of 150 MW each, 5 units of 160 MW each and 2 units of 300 MW each, for a total of 1,850 MW. The TPP at Tkvarcheli (in the Abkazia region) has 2 units of 110 MW each. The combined heat and power (CHP) station in Tbilisi has 3 units of 6 MW each. Among the HPPs, the largest is at Inguri (partly located in Abkazia region) with 1300 MW, followed by five other storage HPPs, 17 large run-of-the-river HPPs (10 MW or above), and 80 small HPPs. The available capacity is however significantly lower, because of the war damages and lack of maintenance for long periods of time. In Gardabani, only the 2 units of 300 MW each were operational with a reduced total capacity of 400 MW. In Tkvarcheli, both the units are damaged and are not operational (and are beyond repair). The Inguri HPP is war damaged and can generate at capacities of around 400 MW only compared to its nameplate capacity of 1300 MW. In 2001, it was estimated that the available capacity varied from 1,200 MW to 1,800 MW depending on water flows. In December 2001, one of the two 300 MW units at Gardabani was damaged and it would not be available for at least another year. Thus the available capacity in 2002 has further shrunk to a range of 900 MW to 1500 MW.

Inguri HPP is being rehabilitated, to restore its capacity to 1300 MW, at a cost of $62 million, financed in part by an EBRD loan of $39 million and grants of $10 million from EU and Japan. Under an agreement signed by the governments of Georgia and China in February 2001, a China-Georgia joint venture company is constructing the Khadori HPP with a capacity of 24 MW at a cost of $27 million. The first 2 MW unit had been commissioned in September 2001, and the rest is expected to be commissioned by the end of 2002. China has also committed to build a 9.3 MW HPP in the river Chelta in the same Khaketi region. Government plans to build new HPPs include: (i) Namakhvani HPP 250 MW, (ii) Zhoneti HPP 100 MW, (iii) Minadze HPP 40 MW on Kura river. It is not clear, however, how funds needed for this would be raised. Also, the government seem to have approved recently, a BOO type contract for a foreign investor to build a thermal plant with two circulating fluidized bed units of 125 MW each using coal from Tkibuli mines. However, the contract has not become effective so far, and is not likely to become effective any time soon.

Transmission, Distribution, and Dispatch

The transmission system consists of 527 km of 500 kV lines, 21 km of 330 kV lines, and 1,173 km of 220 kV lines and 2,661 km of 35 kV lines. Primary distribution is by 20,500 km of 10 kV and 6 kV lines, and secondary distribution is by 53,000 km of 0.4 kV lines. The transmission system is interconnected to those of Russia, Azerbaijan, Armenia and Turkey with a total transfer capacity of 3000 MVA. Many of these tie lines are not operational, causing congestion and transfer problems. The 500 km long 500 kV line is the backbone of the system connecting Gardabani TPP and Inguri HPP and it connects the Georgian system to the Russian and Azerbaijan systems. It passes through the Abkazia province, where it is often subject to sabotage and damage arising from heavy snow falls, causing serious power outages.

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33. According to the Annual Report of GNERC for 2000, the installed capacity had come down to 4,471 MW by Jan 2001. 61.4% of this was hydroelectric and the rest was thermal.

The national dispatch center at Tbilisi dispatches all generating units of 10 MW or above, tie lines to the four neighboring countries, and the transmission network generally above 110 kV lines and some 110 kV lines. 12 area control centers dispatch all remaining generating units, 110 kV lines and the 35 kV network. Of these the area control center at Kutaisi has some additional responsibilities for the western part of the system. At the third level, a number of area control centers dispatch the 10 kV distribution network and lower voltage lines.

Demand

Excluding those in the A and SO provinces, there are about 1.2 million consumers in the country and 98% of them are residential consumers. System demand declined from about 17 TWh in 1989 to about 7–8 TWh during the last few years. In 2000, for example total generation was 7,446 GWh (of which 79.3% was hydro and the rest thermal). Net imports were 401GWh and the total consumption was 7,847 GWh. Annual per capita consumption had been around 1,350 to 1,550 kWh during the last several years. During the same period the industrial demand came down from about 8TWh to about 1 TWh and the share of the residential consumers in total sales rose to 55%–60% range. The total demand is expected to remain at about the current level or increase only slightly during the next several years, especially in context of severe supply constraints, tariffs rising to cover the full cost of supply, and payment discipline (hopefully) strengthening. The existing generation capacity should be adequate to meet this level of demand, provided the generating units are rehabilitated and continuous fuel supplies are ensured. Seasonal variations in production or demand can be managed through imports or exports.

Tariffs

Till 1996 tariffs were heavily skewed in favor of residential consumers, who were subsidized by industrial and commercial consumers. Thus while the residential consumers were charged US cents 1.95/kWh, others were charged US cents 3.21/kWh. In July 1997 when the average tariff/kWh was US cents 3.52, 43% of that was attributable generation charge, 28% to transmission charge and 29% to distribution charge. Under the new Electricity Law of July 1997, Georgian National Electricity Regulatory Commission (GNERC) was created, which introduced the concept of full cost recovery and gradual elimination of cross subsidies. Thus by 1998, the residential tariff/kWh rose to US cents 4.69 while those of others remained at around US cents 3.52. During 1994–1999, the average end use tariff/kWh went up by 200% and stood at US cents 4.5 in June 1999. There was a range of mandated tariff discounts for a wide variety of consumers and the compensation payable by the government to the utility for these discounts generally tended to be sporadic and partial, and always in the form of offsets. The aim was to phase out these indiscriminate discounts and protect only the economically disadvantaged segment of the population through appropriate pension payments in the context of rising tariffs. Early in 2002, GNERC approved a tariff revision under which the average tariff/kWh in Tbilisi distribution area (Telasi) would be US cents 5.32/ kWh[34] while the average tariff/kWh for those in other distribution areas ranged from US cents 3.45. A lifeline rate for poor consumers and a "subscriber fee" for each consumer were being contemplated. Tariffs vary by supply voltage level, broadly reflecting differential supply costs.

System Losses and Non-Payment

The transmission and distribution losses[35] were estimated to have risen to the level of 34.8% by 1997. The situation would appear to have become much worse since then. Presently the losses in

34. At the exchange rate of 2.35 Lari per US dollar in April 2002. In local currency these rates were 12.4 tetri and 8.1 tetri.

35. Including about 750 GWh of electricity (supplied to the A and SO provinces) which are never paid for on account of the civil conflicts.

the distribution level alone are believed to be around 40%. The transmission losses are believed to be high at around 15%. Thus the total system losses[36] including auxiliary consumption of generating units could be as high as 55% to 60% of the gross electricity generated. The overall losses include a great deal of theft losses and illegal and unbilled and un-metered consumption, because of the deep-seated corruption in the relevant organizations. A lack of adequate meters and unreliability of the existing meters (most of them often tampered with) also contribute to this. Theft of electricity is not yet a criminal offence in Georgia, and an amendment to the Criminal Code to correct this situation is pending approval by the parliament. Such an amendment would strengthen the legal deterrent. However, the core of the problem is corruption and lack of willingness to deal with theft.

Non-payment and non-cash payments had been persistent problems since 1992. Collections as a percentage of billings went down to a trough of 20% in 1995 and, as a result of major efforts made by the government under the Bank's lending program, started rising. After the reorganization of the sector, collections at the level of distribution companies stood at 68% in 1997. Of this the collection ratio for the residential consumers was the worst at 39%. The collection at the level of transmission company from the distribution companies was worse at 53%. Of the amounts collected only 45% was in cash; the rest was in barter and offsets. The transmission company thus could not pay the domestic generators as well as the foreign suppliers of electricity and fuels, resulting in suspension of supplies. Lack of funds also prevented adequate maintenance of sector assets, leading to reduction in the available capacity. The country thus faced constantly rotating rounds of load shedding and extremely poor and unacceptable quality of supply. The situation seems to have become much worse in the recent years. Recent Bank missions of October 2001 and February 2002 report an overall collection level of only about 30% in the sector. At the level of the wholesale market, cash receipts represent only 10% of the billings. The government budget financed entities do not get adequate budget provision to pay their utility bills, and political pressure to continue supplies to non paying industrial customers continues to be relentless. The unbilled (or stolen) electricity and the uncollected bills together are estimated to cost the sector more than $100 million annually.

Structural Changes

Till 1995, Sakenergo was a state owned vertically integrated utility responsible for all power sector activities. Though the Electricity Law enabling the sector restructuring was passed only in mid 1997, some amount of structural changes had been taking place even earlier. Some HPPs below 10 MW in capacity (totaling 90 MW) had been sold to the private sector even before 1995. Four larger HPPs with a total capacity of 180 MW were given on long-term lease. Distribution was taken away from Sakenergo and handed over to the municipalities in 1994–1995, thus creating 66 to 70 distribution companies. Sakenergo was then split into two generating companies and one transmission and load dispatch company. The first generation company "Sakenergo-Generation JSC" owned and operated most HPPs and all the TPPs except the one at Gardabani. The second-generation company "Tbilsresi JSC" owned and operated the 1850 MW TPP at Gardabani. "Sakenergo JSC" was the company responsible for transmission and load dispatch. The distribution joint stock companies came to be owned by the municipalities, as a result of the decentralization policy of the government. The government also created under the new law, the Georgian National Electricity Regulatory Commission (GNERC) as an independent entity to regulate the tariffs in the electricity sector on the basis of full cost recovery.

Sakenergo JSC became the single buyer and bought all electricity generated in Georgia at prices regulated by GNERC and sold them to the distribution companies and certain large industrial consumers[37] (called "Direct Consumers") at pooled average prices. Under this arrangement

36. This would be difference between gross energy generation + import – billed sales.

37. Large consumers connected to the grid and receiving supplies at 35 kV or above. They correspond to the "eligible consumers" (as they are called in many other East European and FSU countries) and they can choose their supplier.

collections appeared to improve somewhat and reach the level of 68% at the level of distribution companies in 1997. Sakenergo's collections from the distribution companies were only 53%, while it managed to collect its dues in full from the direct consumers. Debts of distribution companies to Sakenergo amounted to the equivalent of 20 month's sales to them. Distribution companies paid to Sakenergo only 45% in cash, 50% in barter and 5% in offsets. The direct consumers were worse in this regard and paid 37% in cash, 59% in barter and 4% in offsets. This in turn affected the ability of Sakenergo to pay the generating companies and the fuel and electricity suppliers from abroad, resulting in the chaotic condition of the system with a regime of rotating load shedding. In winter 1998/99, Tbilisi had power for only 4 to 6 hours per day. The rest of the country averaged only 3–4 hours of supply per day. Some parts of the country did not get any supply at all.

The municipalization of the distribution function was soon recognized to be undesirable, as it fragmented the small Georgian system (1.2 million consumers and 5 to 6 TWh of sales) into numerous tiny unviable bits, subject to intense local political pressure and intervention. Only the distribution company in Tbilisi (called Telasi) had a reasonable economy of scale with a share of 50% of the national electricity sales and 33% of the total number of consumers in the country. The government therefore regrouped all other smaller distribution companies into 10 larger companies generally coterminous with the administrative regions.

Encouraged by the Bank and EBRD, the government pursued the path of reform involving the privatization of the unbundled entities. Telasi was the first distribution company to be privatized. Based on international bidding carried out among qualified strategic investors with the help Merrill Lynch, 75% of the shares were sold to AES of USA for a value of $25.5 million. AES also assumed the debt of Telasi to the extent of $10 million and agreed to invest $80 million in rehabilitating the facilities.[38] The government did not succeed in privatizing other distribution companies, although it allowed investors to bid for any combination of them. The Government decided to further regroup them into one or two larger companies and attempt to sell them by end 2001. At present, apart from Telasi only one other small distribution company (Khahetia) has been privatized to Georgian entrepreneurs. All distribution companies, other than Telasi, Khahetia and those at Adjara and Abkazia have been merged into one large distribution company. The Government intends to hire a private manager (through a management contract) for this company for a three to five years period, in the hope that within this period the financial performance of the company and the investment climate would improve enabling successful privatization. As noted earlier, nearly 270 MW of small and medium HPPs had been sold or given on a 25-year lease. The government decided to sell or give on long-term lease all other medium sized HPPs. AES of USA got, on a long-term concession, Khrami 1 and 2 HPPs with a total capacity of 223 MW. Negotiations with a Greek company TERNA have been concluded recently for giving a management contract in respect of Vartsikhe hydro cascade system with a total capacity of 184 MW. The government thus plans to privatize or give on management contract all the remaining HPPs outside A and SO regions.

Two units of 300 MW each at Gardabani were sold to AES of USA in April 2000. Six of the remaining 8 units are not operational at all. They have to be decommissioned, if no private party is interested in them. 12 MW of CHP at Tbilisi were also privatized in 2000. Non-privatized entities[39] would be placed under management contract with a special focus on improving their financial control systems and adoption of IAS based accounting till they become attractive strategic investors. Pre privatization debt restructuring would also be undertaken for such units.

In order to enable the functioning of the electricity market, a first step was taken by separating the functions of transmission and load dispatch from Sakenergo JSC and entrusting them to two new 100% government owned companies, the Transmission Company (EG) and the Load

38. At the same time the government agreed to defer Lari 130 million of Telasi's debt to Sakenergo by 99 years.

39. Those with substantial useful life left in them. Units not suitable for rehabilitation would be decommissioned.

Dispatch Company (ED), leaving Sakenergo[40] with no responsibilities for the sector assets or operation and with only the historic debts of the sector. At the same time a new institution called Wholesale Electricity Market (WEM) was created to handle the wholesale market operations. ED and EG are regarded as strategic state assets and would not be privatized. Legally WEM is an association of all sector players- generators, transmitters, distributors and large consumers. Under this sector structure, none of the three entities – ED, EG and WEM – would act as the single buyer in the system. WEM also would not buy or sell on its account, but will act as a settlement agency or a clearinghouse for the collective transactions among the generators, distribution companies and direct consumers.[41] All generators supply to the WEM at prices regulated by GNERC reflecting the capacity and energy costs of each generator. WEM will supply power to the distribution companies, exporters and direct consumers at the weighted average cost of the power supplied to it by the various generators and importers. Dispatch will be on least cost basis. Some bilateral contracts between the generators and importers on one hand, and the distribution companies, direct consumers or exporters on the other hand, would also be allowed with regulated charges for transmission and ancillary services. When such bilateral contract is with a HPP, the buyer will have to reimburse to WEM the difference between the pooled average price of WEM and the regulated price of the HPP.

This wholesale market mechanism had not been functioning well. WEM, in the 2.5 years of its existence, had not been successful in collecting the dues from the distribution companies and direct buyers and had accumulated accounts receivable from them in excess of $210 million and a similar levels of accounts payable to generators, ED, EG, foreign suppliers and others. WEM should pool the collections from the buyers and distribute them pro rata to the sellers (i.e., generators and importers), but had not been able to do this in a fair and transparent manner. In an attempt to overcome these problems, the government decided to award management contracts to experienced foreign utility companies to run WEM, ED and EG. In early 2002 the government also decided to merge ED and EG into one entity and concluded a management contract for it with ESBI of Ireland. Similarly the management contract for WEM had been awarded to Ibedrola of Spain for five years.

The government's original plans for the next phase envisaged that all generators would receive the same price equal to the regulated price of the highest cost supplier during each hour, following the principle of marginal cost. This would need extensive bulk metering and control systems to track hourly supply and consumption. In the third phase generators would make bids for supply during each hour and dispatch would be on the basis of bids and payments on the basis of marginal cost during each hour. This would be possible only when there are a sufficient number of private operators to participate in the competitive bidding for supply. Some amount of bilateral contracting would be allowed in all three phases. These plans have become outdated in the light of the sector conditions, and have to be reviewed and made more appropriate to the sector status.

The operation of the WEM since 1999 had not brought in the anticipated improvement in sector efficiency or performance. About 60 to 65% of the total energy sold passes through WEM and the balance is being sold through bilateral contracts to direct consumers and distribution companies. Of the total sales in 1999–2000, direct consumers bought 21% mostly on the basis of bilateral contracts, Telasi bought about 44% and other distribution companies bought the remaining 35%. Telasi bought more than 80% of its requirements through bilateral contracts, since AES group owns Telasi as well as TPPs and HPPs with total capacity of 883 MW. Telasi was also the largest supplier of cash to WEM. Of the total cash receipts of WEM, 65% to 70% came from Telasi, 25% from other discos and 5% from direct consumers. Overall collection problems and non-cash

40. This company was renamed as "Sakenergo 2000".

41. This aspect is often ignored even by the government, which had occasionally asked WEM to handle fuel purchases, imports and exports and sign PPAs for new generators.

payment problems continued to plague the sector. Collections from households rose from a low of 19% in the second half of 1999 to only 27% in the first half of 2000. While collections of WEM from Telasi improved from 38% in 1999 to 60% in 2000 (of which 80% was in cash), collections from other distribution companies were only at 20% (of which only 50% was in cash). Direct consumers were paying only 22% of their bills (and only 3% to 5% in cash and the rest by way of offsets) to WEM. About 12% of the billed electricity went to the consumers in the A and SO provinces and for political reasons nothing could be collected from them. The government had been able to reimburse to the sector only 10% of these costs and that too, by way of offsets.

One of the major problems faced by the sector in the context of privatization is the large volume of debts consisting of inter-enterprise debts, debts to suppliers, workers, government, domestic and international financing institutions, and neighboring countries. Some of these debts such as those incurred in importing electricity or fuel for the sector do not figure in the balance sheet of any of the sector enterprises. Much of the inter-enterprise arrears would have to be written off sometime. In the context of privatization, if the buyers refuse to accept the debt obligations, the Government will have to find a method of settling the legitimate obligations. In respect of all such debts, which would not be assumed by the buyers, and which could not be settled by offsets or by other means and which could not properly be written off, the government plans (a) to have them rescheduled to secure a manageable level of repayments; and (b) levy a surcharge to the tariff earmarked for the settlement of such debts.

The experience in Telasi after privatization had been mixed. System losses continue to be high at around 40%, but recently decreasing, as AES is completing its re-metering program. Collections improved notably in the first two years and provided a great deal of cash to the market. However, its payments to generators and transmission providers have fallen a little behind, probably because of the non-payments of its own dues by the WEM. AES may also have underestimated the deep-seated corruption and indiscipline entrenched in all segments of the system. The problems are also compounded by a significant lack of law and order and frequent suspected sabotage of facilities. Enforcing internal discipline among inherited groups would also appear to have proven much more difficult than anticipated. Improvement of supply in Tbilisi last year and this year is notable. Contrary to the expectation based on density of load and economies of scale, tariffs in Telasi are about 50% higher than in other distribution areas, and in early 2002 they had received a 40% rise in tariff. Much of this increase is attributable to the substantial investments made by AES. The government also exempted them from the levy of VAT on uncollected bills. A substantial US government grant to the government of Georgia, inter alia, enabled the timely payment by Government of consumer subsidies for winter heat to the Telasi area.

Problems relating to the configuration of the transmission system prevented Telasi from taking full advantage of their ownership of 883 MW of hydro and thermal capacities to meet the demands of Telasi fully or properly. Despite Telasi's prompt settlement of their bills mostly in cash from the WEM, the latter as well as the direct buyers had not been as businesslike in settling the bills of AES owned generating stations. This is partly because of the normal difficulty in any system to disconnect the non-paying distribution companies or the large direct buyers without affecting system stability, and without affecting other paying customers. Mostly though, the collection problems of WEM are attributable to lack of willingness, pervasive corruption and poor governance. Despite this AES was able to improve winter supplies partly in the winter of 2000–2001 and mostly in the winter of 2002–2003.

The Bank, EBRD, KfW, USAID, and EU have played a major role in encouraging the government to carry out the sector reform and the direction it had taken from time to time in unbundling the sector, introducing competitive elements, and more importantly in privatizing the unbundled sector assets. The creation of an independent regulatory body, and an orderly approach to historic sector debts are noteworthy contributions. When privatization proved difficult, the government was encouraged to give assets on long-term concessions, and when that also failed to attract the investors, the government was encouraged to resort to the use of the management contract system

to prepare the assets for eventual privatization. These are all pragmatic approaches as the situation developed. Looking at the developments over the last seven years, one may wonder, in hindsight, whether in such a small system as that of Georgia with 1.2 million consumers and total sales of about 7 TWh, *which is not quite suitable for any meaningful competition,* unbundling and the consequent proliferation of institutions would not have substantially increased transaction costs and needlessly burden the consumers. In terms of cost effectiveness, it is not clear how successful the present approach to sector restructuring and reforms has been. The sector continues to suffer from relentless load shedding, high system losses, poor payment discipline, theft and corruption.

AES having acquired 823 MW of generation and the largest distribution area together is not conducive to competitive markets. The task of preventing such potentially anticompetitive acquisitions and mergers is even more difficult in less developed countries than in many OECD countries, especially in the absence of investor interest in emerging markets. Perhaps arrangements such as these are driven more by the concern to overcome the poor governance and corruption problems of the sector than by the desire to create competitive structures. Such trade offs between competing objectives is not unknown or unwelcome. However, if the main aim of privatization is to overcome governance and corruption problems, privatization could have been carried out with much simpler sector structures.

In retrospect, one wonders whether a reform involving the privatization of the original vertically integrated Sakenergo as a single entity and subjecting it to regulation by an independent regulatory body would not have been a more practical and cost effective alternative. For small systems with little scope for competition such a course of action may be an optimal solution. Before privatization, one would have to correct the technical defects of the system design and improve institutional performance through such devises as management contracts. Overall, the transaction costs could have been contained. The operations of the A and SO regions in any case would have to be ring fenced and financed from the state resources from the internal security budget and not allowed to burden any utility.

The Georgian case illustrates that deep seated problems of law and order, sabotage, corruption, non-payment, and sheer lack of respect for contracts and elementary property rights could not be overcome by sweeping them under the carpet and hoping that privatization would resolve them all. Also, the idea that if we take care of the distribution segment by privatizing it, the rest of the sector can take care of itself is shown to be not very tenable. Further the case also proves that partial privatization ahead of institutional improvements and substantial commercialization of the operations, does not help to get rid of these problems and improve the performance of the sector. It also illustrates that the coexistence of privatized distribution companies (which respect contract obligations and pay their bills) and non-privatized distribution entities (with little payment discipline) results in problems for the former also. Georgia will have to focus on improved commercialization of the sector under management contracts, before being able to attract further private investment. The lull in the investment market gives the country the time needed for this.

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HUNGARY

Introduction

With a population of 10.3 million, Hungary was the earliest among the former centrally planned economies to recover from the economic and political turmoil of the late 1980s and early 1990s and resume growth from 1993. During 1993–2000, its real GDP grew at an average annual rate of 3.5%. By the year 2000, its annual inflation rate had come down slightly below 10% and its per capita GDP stood at around $4,430. It is already a member of NATO and is in the forefront of the candidates for accession to the European Union (EU).

The country produces only about 25% to 30% of its oil and natural gas needs and depends on imports (mostly from Russia) for the remainder. It has lignite resources of about 3 billion tons, brown coal reserves of 1 billion tons and hard coal reserves of about 0.7 billion tons. Most of the lignite and brown coal is destined for power generation. On account of the high sulfur and ash content and low calorific values of the Hungarian coal, its production had been declining from 19.7 million tons in 1990 to 15.3 million tons in 2000. On account of rising mining costs and environmental concerns, coal production for power generation is likely to be phased out by 2010.

Power Sector Dimensions and Characteristics

Generation and Transmission

At the end of 2000, the installed power generating capacity in the country stood at 8,082 MW,[42] consisting of the PAKs nuclear power plant of 1,851 MW (23%), gas fired thermal plants of 3,755 MW, coal fired thermal plants of 1,852 MW, oil fired thermal plants of 580 MW and hydroelectric plants of 44 MW. In addition the country had also captive generating units of industries totaling 198 MW. The available capacity of 7,855 MW and imports of 465 MW met the peak demand of 5,742 MW in 2000. The nuclear power plant is considered one of the 10 safest and best-operated nuclear plants in the world. Some of the coal plants can also switch over to the use of oil or gas and

42. The installed generating capacity in 1997 was 7,350 MW. The information here and elsewhere is from the Annual Report of MVM Rt for 2000 and from the websites of MVM Rt and HEO.

most of them have their own dedicated coal mines. Many of the thermal plants are combined heat and power (CHP) units producing steam and hot water in a cogeneration mode. By 1997, most of the coal fired plants were 30 to 40 years old and it was believed that except for the plant at Matrai (refurbished in the 1980s), most of them might have to be retired in the next five to seven years.

The transmission system used to be a part of the Soviet grid. Since 1992, Hungary upgraded its system to UCPTE standards and became first part of the Central European System and from 1995 part of the UCPTE. A 400 kV line to the West European grid through Croatia was completed in 1999 further strengthening the interconnection. In 1990 Hungary imported 12.2 TWh from Ukraine using the 750 kV line, but since then imports from Ukraine have declined to 1.5 TWh in 2000.[43] Only a small island in the Ukrainian system is connected to and synchronized with the Hungarian power system. Major imports now are from Slovakia and major exports are to Croatia, Yugoslavia and Slovenia. Hungary's transmission system consists of 750 kV lines (270 km), 400 kV lines (1,730 km), and 220 kV lines (1,200 km). There are about 2,600 km of 120 kV lines to which the nuclear plant and other large generating plants are connected. Medium and low voltage lines exceed 145,000 km. Load dispatch is by one national and sixregional load dispatch centers. There are also about 39 distribution control centers.

Demand, Supply and System Losses

The system peak demand in 2000 was 5,742 MW compared to 5,784 MW in 1996 and 6,550 in 1989. Total gross energy generated in 2000 was 35,082 GWh, and net imports amounted to 3,440 GWh.[44] Thus the gross electricity consumption in 2000 amounted to 38,522 GWh, compared to a historic high of 40.7 TWh in 1989 and a historic low of 35.2 TWh in 1992. Sales to end consumers was 31,362 GWh implying a total system loss[45] level of about 18.6%, which is generally acceptable for a system of this size.[46] Of the total sales to end consumers 32% went to residential consumers, 49.6% to manufacturing consumers and 18.4% to others. The demand of the residential consumers remained steady at around 9.8TWh through the last 11 years, while the consumption of manufacturers grew from a low of 10.7TWh in 1992 to 15.2TWh in 2000. The total number of consumers in 2000 was 5.13 million (up from 4.8 million in 1990) of which 93.3% were residential consumers and 2% were industrial consumers.

Tariffs and Collections

Under the Electricity Act of 1962, which was in force till it was superceded by the Electricity Act of 1994, electricity tariffs for end consumers were decided upon by the government periodically. In 1992 the Bank's analysis showed that the tariffs prevailing then were close to the long run marginal cost (LRMC) of supply. The tariffs for all consumers were at 101% to 111% of LRMC, while the tariff for the first block of consumption of the residential consumers was only at 72% of LRMC. Subsequent tariff revisions sought to minimize the cross subsidization of residential consumers by industries and to match the financial costs of supply. After the sector unbundling during 1992–94, bulk tariffs for generators and wholesale tariffs and retail tariffs were determined by the government. The 1994 Electricity Act required that the tariffs cover fully the cost of supply including a 8% return on equity. Despite this explicit requirement, the government had been somewhat reluctant to allow the retail tariffs to rise to their legitimate levels (lest the higher retail prices should exacerbate the high levels of inflation), by suppressing the wholesale price and subsidizing the wholesaler through

43. Hungary's total imports of power also declined during this period.

44. Of this 40.6% was from the nuclear power plant, 30.9% oil/gas fired plants,26.5% from coal fired plants, and 2% was from hydro units and auto generators.

45. (Gross generation + net imports - billed sales) divided by (gross generation + net imports)—expressed as a percentage.

46. Auxiliary consumption at 7.5% is rather high and would come down as new and more efficient units are commissioned and old units are retired. System loss for the 6 distribution companies is in the range of about 11% to 13%. There is scope for improvement here.

budget transfers. The tariffs and the tariff outlook at the time of privatizing electricity entities (1995–1997), while not being ideal, were not considered a major risk. As of March 2001 the overall average retail tariff/kWh was US cents 5.44. The average tariff/kWh for residential consumers was US cents 6.11 and that for industrial consumers was US cents 5.11 (all without VAT). Many believe that that the residential tariffs still enjoy some cross subsidy, that the structure of bulk tariff and wholesale tariff has distortions to be corrected. Tariffs vary by voltage level and time of day.

Compared to many other East European and FSU countries, collections had not been a major problem in Hungary. By and large disconnection of non-paying customer was possible both legally and in practice. Through a series of public enterprise reforms, the problem of insolvent public sector enterprises, which could not pay their utility bills, was properly handled. On the whole the payment discipline in the energy market was not allowed to be eroded even during times of high budget deficits and tight money policy regimes.

Structural Changes

Till 1992, all power facilities in the country were operated by MVM Trust, which was a vertically integrated utility operating practically as a government department. In the early 1990s Hungary had accumulated substantial foreign debts and as part of the economic transition, the government desired to privatize appropriate segments of the sector to strategic foreign investors and use the proceeds to reduce external debt. Further the aging sector assets would need expensive replacements, and financing the up-front capital needs of such replacements through fresh external government borrowing was not considered a viable option. Privatizing the assets and letting the new owners to invest in replacement and new assets appeared a practical solution. Thus, in 1992, as a precursor to privatization, the government embarked on sector unbundling, corporatization and establishing wholesale and retail electricity markets on the basis of the single buyer model.

Thus MVM Trust was unbundled in 1992 into eight generating companies,[47] six distribution companies and one company for transmission and load dispatch (called OVIT). MVM Trust itself was converted into a holding company for these entities and was registered as MVM Rt and incorporated under the company law. All the unbundled companies were also incorporated under the company law. Nearly 98% of the shares in MVM Rt were held by APV Rt[48] on behalf of the state and the remaining shares were held by the municipalities. MVM Rt held 50% of the shares in all subsidiaries and APV Rt held about 48% and the municipalities held the remaining shares. In 1993–94, five of the generating companies had their supplying coal mines individually integrated with them. In the context of privatizing the distribution companies APV Rt swapped its share holdings in the nuclear plant and in the transmission company (OVIT) for the share holdings of MVM Rt in the six distribution companies.[49] Thus MVM Rt became the full owner of the nuclear power company, as well as the transmission and load dispatch company. In addition it had also the full ownership of the three gas turbines (410 MW) kept as system reserve. In 2001, the load dispatch function was separated from MVM Rt and entrusted to a 100% MVM Rt owned subsidiary called MAVIR Rt to serve as Independent System Operator. In early 2002 this company was transferred to the direct ownership of the Ministry of Economic Affairs of the government to ensure a greater degree of separation and independence from the transmission operator.

Single Buyer Model

The restructured system was operated on the basis of the single buyer model. All generating companies were obliged to sell their output to the wholesaler MVM Rt on the basis of power supply

47. PAKS nuclear plant was also one of the 8 generating companies.
48. Hungarian State Privatization and Holding Company.
49. This resulted in substantial book losses to MVM Rt for two reasons: (a) the book values of the PAKs shares were lower than those of the six distribution companies; and (b) asset sales while privatizing were at prices lower than book values.

contracts - usually annually agreed upon for the next few years - and at the agreed bulk supply prices, which reflect the cost of generation and varied from unit to unit. All six distribution companies were obliged to buy all the power they needed from MVM Rt at a uniform wholesale price (reflecting MVM Rt's average cost of purchased power and the charge for transmission and ancillary services) on the basis of similar purchase contracts and sell power to the end consumers on the basis of regulated retail tariffs. MVM Rt had also the exclusive right to import and export electricity.

Till 1996, the bulk supply prices of the generators and the wholesale price were determined by MVM Rt, while the retail sales tariffs were determined by the Ministry of Industry and Trade of the government. In the context of privatizing generation companies, MVM Rt signed formal Power Purchase Agreements (PPAs) with the new owners for about 10 years (on a take or pay basis), with agreed capacity fees and energy fees. The bulk supply tariff for each generating unit was determined on the basis of recovering fully all costs including depreciation on partially revalued assets and 8% return on proportionate equity. The wholesale price was determined as the sum of: (a) the pooled average cost of power purchased from domestic generators and imports; and (b) the regulated charges for transmission and ancillary services, and it was same for all distribution companies. The distribution companies sold electricity to the end consumers in their franchise area at regulated retail prices, which were uniform throughout the country. Since then all three prices are determined by the government on the basis of calculations and proposals made by the Hungarian Energy Office, in terms of the Electricity Law of 1994 which was scheduled to come into effect in January 1997. This law provided the legal basis for the sector unbundling, operation of the single buyer model and the price regulation mechanism. It is important to note that since all six distribution companies bought at the same wholesale price and sold at the same retail prices, their margins or profitability depended on the efficiency of their operations and to some extent on the consumer mix and the system configuration of their franchise area.

Under the model followed in Hungary, there is no competition, no choice for any consumer to choose his supplier, and no third party access to the transmission and distribution wires services. Since MVM Rt has the responsibility for load forecast, and least cost capacity expansion planning, and purchases power from the existing and the new generating companies on the basis of long term power purchase contracts with take or pay provisions, the investors in generation and distribution have practically no market risk. It was envisaged that new generation capacity would be added on the basis of competition, in the first instance, among existing generating companies, and if no more than 3 offers came from them to resort to international competitive bidding among strategic investors. Thus this model does not provide for much competition, while making the sector attractive to the investors and making privatization some what easier and more rapid. Thus a deliberate choice was made in favor of privatization before competition, which would come at a later stage to comply with the requirements of EU accession. The aim of the government was to create a credible governance structure, cost recovery tariffs, and transparent regulation involving licensing as a prelude to privatization of generation and distribution assets.

Privatization

As mentioned earlier, the key motivation for privatization came from the desire to: (a) reduce external debts with the proceeds of privatization of selected assets to foreign strategic investors; (b) avoid further external borrowing for replacement of aging assets and adding new capacity (to avoid import dependence—a condition for being a member of UCPTE); (c) to improve sector efficiency; and (d) to shed activities which need not be in the public sector in the context of transition to the market economy.

Even while the structural changes were in progress and the new electricity law had not been enacted, the government made an attempt to sell 15% of the shares in the distribution companies in 1993. This offering of the minority shares did not attract the strategic investors, especially when the necessary legal framework and other prerequisites such as policy on tariffs and returns and market rules were not in place. The first serious and mostly successful attempt was made in mid 1995

after the enactment of the Electricity Law of 1994. The new law and the associated regulations: (a) created a credible, if not an entirely independent, regulatory office in HEO;[50] (b) clearly laid down the tariff principles involving full recovery of all justified costs including a return of 8% on the proportionate equity[51] and the nature of price regulation as one following price cap methodology;[52] (c) indicated that the price cap tariffs would be valid in the first instance through 2000 and updated thereafter; and (d) that the tariff formula would be applied individually for the generating companies and the transmission company and collectively for all six distribution companies. Schroeder of UK was engaged as the financial advisor and an information memorandum was prepared including not only the enacted legislation, but also the drafts of regulations not yet issued (such as those for environmental obligations). Further notable elements in the exercise were:

- Agreements with labor unions were reached on continuity of employment, levels of future employment, salaries and benefits, and these were to become part of the privatization contract;
- 5% of the privatization proceeds to be kept in a Special Fund to assist workers who lose their jobs;
- Oblige the buyers to retain the existing managers for a minimum period of two years;[53]
- Prohibiting the buyers from selling their investment for five years.

The invitations were issued on the basis that the offering was for 21 to 49% of the shares in seven generating companies[54] and six distribution companies with an option for the investors to acquire majority stakes by 1997. However the investors would be given immediately management control of the company and majority of seats on the Board. The government would retain a golden share in each company, which would oblige the company to secure government concurrence for changes in capital structure, changes in business profile, and more importantly *acquisitions and mergers* and dissolution.[55] With remarkable speed, the evaluation of bids was completed, decisions reached, deals concluded, and privatizations contracts signed by the end of 1995. In this round all six distribution companies and only two generating companies (Dunamenti and Matrai) were successfully sold.

The five remaining generating companies did not attract the interest of strategic investors because of their concerns regarding: (a) the high cost of owning the integrated coal mines; (b) stringent environmental obligations; and (c) the high minimum price set by the government. After making adjustments to the documents to allay these concerns[56] and by offering majority shares straightaway, two more generation companies (Budapesti and Tiszai) were sold in auction to strategic investors in 1996 and 1997. A further two generating companies (Pecs and Bakonyi) could be sold only through negotiations, on account of coal mine related complications, basically by reducing the asking price. The seventh generating company, Verteszi, could not be sold and still remains with 84% combined shareholding by MVM Rt and APV Rt. The privatization proceeds amounted to $1.5 billion. The proceeds from the sale of the 6 distribution companies amounted to $1.1 billion or $39,231 per GWh of the distribution companies' annual sales, compared to

50. Actually HEO was named as the regulator for electricity and gas sectors under the new Gas Law of 1997.

51. Proportionate equity = Total equity × (fixed assets in use or usable for power/total fixed assets).

52. Prices determined on the basis of present costs and cost expectations for the next 3 to 5 years. These would be allowed to rise during this period by the formula RPI-X where RPI stands for retail price index and X stands for a coefficient for efficiency gains. However if the actual return exceeds 12%, one half of the surplus return would be returned to the consumer.

53. 30% of the workers lost their jobs but it did not result in any notable agitation. Most managers were retained well beyond the two year period.

54. All except PAKS nuclear plant, which the government decided to retain in the public sector.

55. It is important to note that this may be an effective way of preventing anti-competitive type of re-integration of sector assets through acquisitions and mergers.

56. For example, book losses of Budapesti were absorbed by the government and some environmental obligations were deferred to a later compliance.

$136,739 realized in UK or $292,059 realized in Australia or $226,215 realized in Latin America.[57] However, among the East European and FSU countries, Hungary's record was probably the best. The investors in distribution were Bayernwerke, RWE, and EdF. In generation the investors were Tractabel, AES, and RWE. Later three new IPPs entered the picture of which PowerGen with a new capacity of 389 MW of combined cycle gas turbines in Csepel Island near Budapest was prominent. Thus the distribution sector is entirely in the hands of foreign strategic investors, while foreign strategic investors owned nearly 70% of the generation facilities in the country.

Post-Privatization Issues

In 1996, HEO calculated the tariffs required to meet the 8% return on equity requirements, taking into account the actual audited cost structure prevailing then and expectations of cost changes through 2000 and it showed that tariffs at all three levels needed to be raised by 35%. These were times of high inflation in Hungary (in the range of 25 to 30%) and the government, which was aiming to bring them down to a single digit figure, was not inclined to exacerbate the situation by raising retail tariffs to such a high level. After a great deal of discussions, the government agreed to an increase of only 24.9% effective from January 1, 1997. The reduction was achieved by: (a) deferring the date by which the non-privatized generation and transmission assets (i.e., MVM Rt, PAKs nuclear plant etc) would be allowed to earn the 8% return; (b) postponing the creation of reserves for decommissioning of the nuclear station, closure of coal mines, and strategic stockpiling of fuels; and (c) non-recognition of expenses such as insurance, proper disposal of contaminated wastes etc. In the context of numerous minor disputes with the privatized utilities, the government also decided on quarterly revision of tariffs, fuel pass through provisions, and recognition in the near future of the above disallowed items, as well as the gradual correction of the distortions in the tariff structure. There had at least been three cases in which the investors went to courts on appeal against the decisions of HEO or government and had the matters resolved. Early in 2001 the constitutional court turned down the provision of the Electricity Law of 1994, which allowed the distribution companies to maintain the existing equipment on public land at no cost. Based on this a small town Mayor presented distribution company EDSAZ with a bill for $25,000 as rent for the poles standing in his town. Had all the Mayors followed suit, the industry would have been faced with a bill for $250 million or about 25% of the total market capital of the distribution sector. The industry went to the high court on this and got a ruling that no annual rents are payable on existing poles.

A major problem arose when the initial period for the price cap period expired at the end of 2000 and tariffs had to be revisited again. Calculations by HEO based on a reexamination of the actual cost structure in 2000 and the cost expectations for the next few years indicated a need for the tariff revision by 18.5%. The government once again baulked at such high increases of retail tariffs and notified a bulk tariff increase of 18.5%, a wholesale tariff increase of 13% and only a 6% tariff increase of the retail tariffs, thus adversely affecting the margins of both MVM Rt and the distributing companies. The six distribution companies refused to pay the higher wholesale price and mounted a strong protest, in response to which the government issued a decree in July 2001 reducing the wholesale price increase also to 6%. Thus while the interests of the strategic investors in generation and distribution were protected, MVM Rt ended with a negative margin. The government gave a direct subvention of HUF 32 billion ($128 million) from its budget to MVM Rt for the year 2001 to make up for its losses.[58] Problems of this kind are inherent in the single buyer model, which enables government to keep the retail tariffs down and distorted, at the expense of the non-privatized part of the sector and ultimately of the tax payer.

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57. Mangesh Hoskote, *Privatization Strategies in Electricity Distribution*. Presentation made on April 7, 1999 in the World Bank Energy Week of 1999.

58. MVM Rt chairman Katona had been quoted as saying that his company incurred a negative margin amounting to HUF 55 billion in 2001, but that the government chose to compensate the company only to the extent of HUF 32 billion.

Cautious Move Toward Competition

After a great deal of debate among reformers and those opposed to further reform, a new version of the Electricity Law was enacted on 18 December 2001, which enables the liberalization of the Hungarian electricity market to conform to the requirements of EU accession. The new law would become effective in January 2003. The Law aims to: (a) provide consumers with secure and low cost electricity supply; (b) develop an objective, transparent and nondiscriminatory regulation; (c) promote the establishment of a competitive market in electricity; (d) create regulated access to the electricity networks; and (e) align existing regulations with those of the EU. The Act envisages the parallel operation of a Public Utility Market and a Competitive Market. The public utility market will comprise MVM Rt as the wholesaler and the six distributing companies as retailers and they would function on the basis of regulated prices with an obligation to supply captive consumers in their respective franchise areas. In the competitive market there would be "eligible consumers" (the Act calls them "authorized consumers") who will be free to choose their suppliers within or outside Hungary, and licensed energy traders who could buy from the generators and sell to eligible consumers on negotiated prices. Initially those with annual energy consumption of 6.54 GWh or above would qualify to be authorized by the regulator as eligible consumers. Presently such consumers number about 300 to 400 and their total consumption is about 30 to 40% of the total electricity market in the country. Till Hungary actually becomes a member of EU (now expected in 2004 or 2005) such consumers may not import more than 50% of their electricity needs.

MVAIR Rt, now directly owned by the government and independent of MVM Rt and all other players in the sector would act as the Independent System Operator (ISO) providing regulated access to the grid for eligible consumers in a nondiscriminatory manner and at regulated transmission prices. ISO will be responsible for balancing the system integrating the short term and long term capacity plans and trade contracts and operating a price monitoring system with increased transparency. Bidding for new capacities is expected to be handled by the regulator, HEO.

In a liberalized market with possible cheaper imports from abroad, MVM Rt may not be able to abide by all the PPAs in terms of the quantities of power it has contracted to buy and may have to pay capacity costs without taking any power.[59] The new law specifies how such stranded costs would be recovered from the market through appropriate surcharges paid into a separate account maintained by the regulator. Most PPAs signed with existing plants at the time of privatization had relatively short duration PPAs and most of them would expire by 2003. The new plants generally have a PPA duration of 15 to 20 years and in respect of them the stranded cost could amount to $200 million during 2003–2010.

The new act seems to increase the independence of the regulator somewhat, though the actual tariff notifications or decrees would still need to be issued by the Minister. The new act also contains notable provisions against acquisitions and mergers resulting in accumulation of market power eroding competition in the market or effective reintegration of functions. Thus no generation licensee can hold more than 30% of the total generation capacity. No distribution licensee can control more than three distribution systems. No distributing company with more than 15% of the distribution market can control over 15% of the generation capacity.

Outlook for the Future

Thus the country carried out its structural reform during 1992–95 and privatization during 1995–1998 and would be moving towards partial liberalization from 2003. From 2003 about 30 to 40% of the electricity would be competitively traded, while the remaining 60 to 70% would be sold

59. MVM Rt's chairman Katona has been quoted as saying that in the context of liberalization, the prices mentioned in the PPA would be renegotiated on the basis of both parties sharing the risk. Also under the new law, when a generator sells his output under the PPA in the competitive market, the capacity fees payable by MVM Rt would be correspondingly reduced for that year.

in the regulated public utility environment. In the wake of Californian experience, most European governments seem to be concerned with security of supply and prevention of sudden and unexpected volatility. Thus further liberalization moves by Hungary are expected to be cautious, and at best incremental. Under the present setup MVM Rt continues to be a very major player in the sector with over 40% of energy generation, control over transmission and broadly over imports and exports and is likely to play a major role as an energy trader too. It may yet emerge as an "electricity champion" in the European scene, as the former prime minister Orban predicted a few months ago. With nearly 70% of the market being in the regulatory regime and in the single buyer mode, it will still be open to the government to subsidize the retail captive consumers, by squeezing the margin of MVM Rt and providing it budget support for the lost margin. One may hope the presence of strategic investors in the generation and distribution sectors, and the partial opening of the market, may generate the necessary momentum towards greater opening of the market.

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Kazakhstan

Introduction

With an area of 2.7 million square kilometers, Kazakhstan is almost as large as Western Europe and four times larger than Texas. It has a population of about 16.8 million, 39% of which is believed to be below the poverty line. Its energy related natural resources are immense. Its proven oil reserves are estimated at 5.4 billion to 17.6 billion barrels, while the estimate of its possible oil reserves dwarfs these numbers. Its oil production, which exceeded 803,000 barrels/day in 2001, is forecast to reach 1.2 million barrels/day in 2005 and 3 million barrels/day in 2010. Foreign direct investment in its oil sector during 1991–2001 exceeded $10 billion. Delivery of the oil to the export markets is proving to be a bottleneck owing to the location of the country and lack of oil pipeline infrastructure. Its proven natural gas reserves are estimated at 65 to 70 trillion cubic feet (TCF) and it is in the top 20 countries in the world with very large gas reserves. Yet it has a small and dwindling production of natural gas at 162 billion cubic feet (BCF) in 1999 and is forced to import gas from Uzbekistan and Russia because of the lack of gas transmission infrastructure. Most of the associated gas is flared for the same reason. The country's coal reserves are estimated at 37.5 billion tons, most of it being anthracite and bituminous coal. It is the third largest producer of coal after Russia and Ukraine in the former Soviet Union (FSU). With a production of 75 million tons and a consumption of 20 million tons in 2000, it is the largest coal exporter to the other FSU states.

Driven by oil price increases, the country's economy registered notable increases in its GDP growth-1.7% in 1999, 9.8% in 2000 and 13.8% in 2001. Annual rate of inflation came down to 6.6% in 2001 and is forecast at 5.6% for 2002. The local currency Tenge is stable[60] at around 158 Tenge to a US dollar in 2002. Unemployment in 2001 was reportedly below 3.3%. The country has at present a trade surplus and a budget surplus.

60. The currency declined in value from 67.30 Tenge to one US dollar in 1996 to the present level.

Table 1: Electricity Generation, Imports and Exports of Kazakhstan
(TWh or billion units)

Item	1992	1995	1997	1999
Generation	78.6	63.2	52.0	44.4
Imports	28.6	8.0	8.6	3.1
Exports	15.4	2.5	1.7	0.2

Nearly 70% of the consumption is in the industrialized northern part of the country.

System Dimensions and Characteristics

The electricity system, however, appears to be in a bit of a mess. Its installed generation capacity was estimated at 18,240 MW consisting of 4 large thermal power plants (8,630 MW), 12 hydroelectric plants (2000 MW), and 38 combined heat and power (CHP) plants (7,610 MW). Due to their age and lack of maintenance the available capacity was estimated in 1999 to be 13,840 MW. The country's only nuclear power plant in the Caspian sea port of Aktau was shut down in April 1999 after 26 years of operation. Plans to build a new 3 x 640 MW nuclear power plant have been abandoned. The government however plans to build 4 new CHP units (2,380 MW) and a new hydro unit (300 MW). A private investor (AES) is rehabilitating two major hydro projects and several CHP units. A joint venture between Kazakhstan and RAO UES of Russia would soon rehabilitate the large Ekibastuz-2 thermal power station.

The electricity system was built during the Soviet Union days mainly to feed the load centers in Russia and not to make Kazakhstan electrically self sufficient. Thus the transmission system consists of three grids: (a) the Northern Grid with about 70% of the country's electricity generation and consumption and with strong 1,150 kV links to the Russian system; (b) The Southern Grid with good interconnections to the systems of Kyrgyz Republic and Uzbekistan and with only one 500 kV tie line[61] to the Northern Grid; and (c) the Western Grid which has two subsystems, each unconnected to any grid in Kazakhstan but connected to Russia, helping them to import power from Russia. The transmission system consists of 1,423 km of 1,150 kV lines, 5,435 km of 500 kV lines, and 19,000 km of 220 kV lines. Its distribution system consists of 110 kV, 35kV and other standard lower voltage lines. The distribution is organized into 18 distribution companies each covering an oblast (region), or a major municipality.

With the collapse of the Soviet Union in 1990, and the contraction of GDP, dwindling revenues and runaway inflation during the ensuing years, the electricity demand fell. This was exacerbated by the pervasive and massive level of non-payment for electricity and the inability of the country to pay for the imported electricity and gas and to maintain its electricity assets in operable conditions. Thus the available capacity and energy fell even faster than the fall in demand. During most of the 1990s load shedding and system outages became the order of the day and network losses and deterioration in the quality of service reached unacceptable levels. Electricity generation, imports and exports fell continuously during the 1990s (see Table 1).

The transmission and distribution losses are believed to be around 15%. Extensive illegal consumption of power and theft of power as well as distribution wires and equipment, as well as a persistent high level of non-payment for the electricity consumed are reported even after the distribution companies came into the hands of private operators.[62] Apart from non-payment, payment through barter and offsets was also a persistent problem. As late as in 1999, collections were reported to be 64% of the billing. Only 50% of the collections were in cash, 25% was in the form of

61. Improving the north-south interconnection and stabilizing both grids is one of key objectives of the Bank's Transmission Rehabilitation Loan of 1999.

62. For example, Pavlodar region's energo service sought and obtained tariff increases from 2.9 Tenge/kWh to 3.8 Tenge/kWh in January 2001 mainly on these grounds.

barters and 25% was in the form of offsets. The accounts receivable of the transmission entity was reported to be equivalent to 218 days sales in 1999. At the level of the distribution entities, it tended to be substantially higher, especially in those under state ownership. Two special reasons had been cited in Kazakhstan as exacerbating non-payment in the past: (a) the local authorities abused their power and notified indiscriminately all kinds of consumers as providing essential public service and thus exempt from disconnection of utility services for non-payment; (b) the metering, billing and collection agency in each region (called energobeist or KSK) was functionally separate from the utility, and sent one bill to each customer for electricity, gas, heating and other public services and the collections which came were apportioned and sent to various utilities and services. This agency had no special motivation to maximize collections of any particular utility, ensure accuracy of meter reading, detection of theft, etc.

The levels of end-user tariffs determined by the national and regional offices of the Antimonopoly Committee were significantly lower than the supply cost and the structure skewed in favor of the residential consumers. Thus in 1997 the average industrial tariff/kWh was 4.69 Tenge or US cents 6.09, while the average residential tariff/kWh was 4.0 Tenge or 5.19 US cents. The distribution margin in this at US cents 0.9 was considered to be 22% lower than the cost. The overall average tariff/kWh in Kazakhstan in 1998 was reported as US cents 4.4, consisting of generation charge of 2.0 cents, transmission charge of 0.5 cent, a distribution margin of 0.9 cent and the cost of transmission and distribution losses at 1.0 cent. The residential tariff continued to be lower than the industrial tariff by about 15%. Another US government source reports the following tariff history, perhaps using slightly different exchange rates:

TABLE 2: ELECTRICITY TARIFF HISTORY FOR RESIDENTIAL CONSUMERS (US Cents/kWh)

Year	Tariff
1994	4.2
1995	3.2
1996	3.0
1997	3.8
1998	4.7
1999	3.1

The end-user tariff is not uniform for all regions in the country. They vary from region to region. Further the tariff in US cent terms seem to have fallen during 1998–2001 on account of the large devaluation of local currency (from about 78 to 145 Tenge to a dollar). Information from a source in EBRD indicates that the average tariff/kWh in Karaganda region in May 2001 was only US cents 1.6, and was inadequate to provide any return on equity and could not provide sufficient cash flows to service debt.

Structural Changes

Before July 1995, all power sector assets in Kazakhstan were owned and operated by Kazakhenergo as a vertically integrated state owned utility. Kazakhenergo had the national level transmission grid, national dispatch center, 10 regional energos and a number of design and construction enterprises under its control. The regional energos operated the electricity and heat generating units and the distribution networks for heat and electricity in their region. Ministry of Energy had the policy responsibilities and administrative oversight of the sector. The end-user tariffs were determined by the national and regional offices of the Antimonopoly Committee. In the context of impending system collapse in the mid 1990s, the government decided to undertake a very rapid privatization of the sector and through the Resolution No. 1033 of 1996 reorganized the sector into a Russian style

two tier system. At the national level, a new entity called National Energy System Kazakhenergo (NES Kazakhenergo) was created to handle the national transmission system, national dispatch center and the large generating units connected to the national grid. At the regional level, the regional energos handled the regional distribution system and the smaller generating units feeding the regional distribution system. Resolution No. 663 of May 1996 enabled the generating companies to be legally separated from the networks and also enabled the transfer of district heating related assets to the city and local government bodies. Resolution No. 499 of July 1996 enabled the registration of these SOEs as joint stock companies with 100 % of the shares being owned by the government. The State Property Committee exercised the ownership functions in respect of such companies. Within this framework the government undertook to privatize generation, transmission and distribution.

Based on private and confidential negotiations with interested private investors, both local and foreign, around 80 to 90% of the generating capacity was privatized mostly by asset sales (in the case of thermal units) and by the grant of 25 to 30 year concessions with equity options (in the case of hydro units). In most of these cases the sale was made in the context of NES Kazakhenergo (in the case of large generating units connected to the national grid) and Regional Energos (in the case of generating units feeding the distribution networks) signing a power purchase agreement with the buyer of the generating units. The prices in these PPAs were determined by the Antimonopoly Committee based on a justified cost plus formula. The overall aim was that Kazakhenergo will act as the single buyer for all privatized generation and sell power to the regional distribution companies and large consumers. The investors included well known strategic investors such as AES Power of USA, Tractabel of Belgium, and other mines and mineral related entrepreneurs such as Japan Chrome, Samsung of Korea, Ispat Karmat of India, and Access Industries of USA. While no precise information was available on the size of the privatization receipts, it was believed by most observers that generation assets were sold for an incredibly low value,[63] the government assuming in most case all existing debts, wage arrears and unpaid pension liabilities.

Negotiations held with ABB of Sweden and National Power of UK for managing the national grid on a contract or concession basis did not succeed. There was also a report that for a brief period ABB was actually awarded 1997 a 25 year contract to manage the power grid, but it was abruptly cancelled very soon. Thus the national grid had to remain in the public sector.

The government succeeded in privatizing 3 of the 18 regional distribution companies in the first round through the method of granting a long term concession for operating the distribution network with equity option. These were: (a) electricity and heat distribution networks in Almaty region sold to Tractabel of Belgium; (b) electricity network in Karaganda region to National Power of UK (in association with Ormat of Israel); and (c) electricity and heat networks in Altai region to AES Power of USA.

Under Decree No. 1210 of July 1997, NES Kazakhenergo was converted into a joint stock company and named Kazakhstan Electricity Grid Operating Company (KEGOC) to own and operate the national electricity grid and the national dispatch center as well as to manage under a management contract to the State Property Committee, the non-privatized generation units (mainly the 2000 MW Ekibastuz-2 coal fired thermal plant and the Shardara Hydropower Company) and 10 of the 15 non-privatized regional distribution companies (REKs).[64] The remaining 5 REKs were directly handled by the State Property Committee. The liabilities of former NES Kazakhenergo (a SOE) in terms of PPAs signed with private generating companies devolved on KEGOC (a limited liability company), and some of the private investors considered this a dilution of the guarantees inherent in the PPAs.

63. For example Tractabel is believed to have purchased the heat and electricity distribution systems and 5 CHP units in the Almati region, which is the country's largest distribution market for a price of $7 million. AES Power is believed to have bought Ekibastuz –1 Power station (4000 MW) for US$5 million and Two hydro stations (1030 MW) and four CHP units (352 MWe and 2000MWt) for $22 million.

64. There is also a report to the effect that since November 2000, AES Power is managing the power grid in Eastern Kazakhstan under 15 year Management Contract.

During the period between 1999 and 2002, the government is believed to have privatized all remaining generation capacity except a peaking hydro plant (remaining with the Ministry of Energy) and all remaining REKs, though no details are available. 51% of the shares in the Ekibastuz-2 plant are believed to have been given to RAO UES of Russia for settling electricity arrears to Russia amounting to $300 million. The joint venture with RAO UES is expected to create a vertically integrated energy company called Ural Heating and Energy Complex uniting several Russian power stations, Ekibastuz-2 and two coal mines in Kazakhstan.

Even though the aim was to unbundle the sector, privatization in some cases, resulted in the creation of vertically integrated private power utilities. Thus in Almaty, Tractabel had not only the electricity and gas distribution networks but also the five CHP units providing electricity and heat to the area. Similarly, in Karaganda region, National Power/Ormat got both the electricity distribution system and the generation facilities. Same was the case in Altai region with AES Power. Such reintegration was not conducive to competition.

The single buyer model originally envisaged by the government could not operate in practice, because of the massive non-payment and non-cash payment problem. KEGOC and the government could not honor the off-take guarantees in the PPAs and the investors realized the futility of trying to enforce their PPAs. Thus came into the existence the bilateral contract market in which the generators sold power only to those (large consumers and REKs) who were solvent enough to pay for the power supplied and since such solvent customers were few, the generators became price takers and had to sell at prices substantially lower than the prices derivable from their PPAs. KEGOC handled the dispatch in terms of the bilateral contracts without the facility of a spot market or a balancing market, relying almost exclusively on selective load shedding to prevent buyers from consuming more that what they contracted with the seller. KEGOC also uses load shedding as a weapon to enforce payment of its transmission charges. The Bank's policy dialogue focused on the collection improvements, reduction of accounts receivable, elimination of barter and minimization of offsets and in that context move towards the creation of the "day-ahead market" and "balancing market" based on bids from generators to effectively supplement the bilateral contract market. Transmission and metering improvements for this are also being addressed. The Government has set up in 2001 a 100% government owned entity called Kazakhstani Market Operator for Electric Energy and Capacity (KOREM) to organize the "day ahead" market and spot market in the course of a year or so. The Bank is advising the government to have its market rules reviewed by international experts and to proceed with the initiative in a cautious and experimental manner in stages.

Kazakhstan enacted a new Law on Natural Monopolies in July 1998 and a new Law on Electricity in July 1999. These laws generally envisage competitive trade in electricity as a commodity and regulated prices for the network services. Under the Law on Natural Monopolies, an Agency for Regulation of Monopolies, Protection of Competition and Support of Small Business (commonly called Antimonopoly Agency or AMA) was created to regulate the electricity business. Its responsibilities mainly are to determine tariffs, to approve investments and to determine allowable costs. The main law itself is silent on the substance of these aspects, which are left to be handled through subordinate legislation such as decrees, resolutions and regulations under the law. The AMA reports to the Prime Minister, but its members do not have any statutory protection of their tenure. The AMA's national office deals with the regulation of the national grid and the generators who are connected to the national grid, while its regional offices regulate the end user tariffs based on the principles and regulations on methodology issued by the national office. AMA at both levels is widely believed to be subject to heavy political pressures and influence. AMA can be required by the law to review its decisions; a recourse to judiciary is also provided for aggrieved parties. Given the lack of expertise of the courts in such matters and the widespread lack of credibility of the justice system, these provisions do not seem to provide comfort to the private investors.

By and large the generation tariff is governed by the bilateral contracts even now and is far below the "regulated tariff" indicated in the PPAs. Generation tariffs would not be regulated once spot/balancing markets are organized and full competition sets in. The transmission tariff/kWh

consists of a fixed fee (on a postage stamp approach) and a distance fee based on the distance between the supplier and buyer. Based on the Bank's policy dialogue, this methodology is being reformed to move away from the concept of distance based tariff and to focus on such elements as the energy transmitted, peak MW transmitted, congestion charges and charges for ancillary services (such as hot and cold reserves and reactive power for frequency and voltage regulation and reactive compensation) apart from the debt service needs and profit elements. The end-use tariff is regulated in a manner prone to constant political interference and is generally believed to be inadequate to cover costs. It is claimed that the distribution margins are squeezed by using unrealistic norms for technical losses and theft of power and for collections, which are considered unfair in the context of widespread theft of power, high technical losses and pervasive non-payment and non-cash payment.

It is believed that essentially based on tariff disputes, Tractabel chose to divest all its energy assets (which also included the gas transmission system acquired at a cost of about $30 million) in Kazakstan and walk out in 2000 based on a compensation award of $100 million. Similarly National Power of UK has withdrawn from their investment in Karaganda area leaving their associates Ormat to be the sole owner of the assets there. It is not clear how much foreign private interest there is in Kazakhstan's electricity sector for fresh investments. The Almaty assets disinvested by Tractabel reverted to the government and are being held now by a new government created company called KazTransGas[65] with shareholding from the City of Almaty and some of the local banking groups.

Lessons from Kazakhstan's Experience

Restructuring and privatization have been going on in Kazakhstan for over seven years. The government adopted non-transparent methods and direct negotiations with the interested party for asset sales without issuing any international tender. It sold assets in the context of a system collapse, instead of first trying to fix the system. Unlike in Russia the government did not focus on eliminating or minimizing barter and offsets and making cash collections somewhat tolerable before embarking on asset sales. Also before embarking on privatization, it did not appear to have: (a) a clear picture of the ultimate desired sector structure; (b) a clear idea of the stages, time frame, legislation or strategy needed to reach the final goal; and (c) a competent and autonomous and accountable regulatory body underpinned by an appropriate law and needed regulations. Thus it did not prohibit investors in distribution networks from acquiring the generating units feeding those systems and thus allowed the creation of private vertically integrated utilities not conducive to competitive markets. This type of an approach resulted not only in extremely poor privatization proceeds to the state, but also in the exacerbation of sectoral problems. While a system collapse was prevented,[66] system reliability was not achieved by a system of dispatch dependent on load shedding to balance the contracted supply and legitimate demand in an environment of extensive non-payment. No arrangement for a meaningful competition could emerge in such a milieu. Regulation continued to be somewhat arbitrary and subject to constant political interference both at local and national levels and tariff disputes resulted in at least two international investors disinvesting their energy assets in the country and walking out. Private investors (AES in Altai region, National Power in Karaganda region and Tractabel in Almaty region) did achieve spectacular improvements in the collection of electricity and heat dues. Collection in cash and cash equivalent rose in these regions from the 20 to 30% range to the 90 to 95% range. However, with the exit of Tractabel from Almaty region, collections seem to have fallen back to 30%.

The laws relating to electricity did not clearly spell out the tariff principles so that subordinate legislation (such as decrees or regulations) could not subvert, at any time in the future, the intent of the law. The law did not ensure the autonomy of the regulatory body and did not insulate it

65. This a large public sector company set up to handle gas transmission in Kazakhstan.

66. The private investors did rehabilitate the generating units and brought production capability adequate to meet demand.

from undue political interference. Nor did it allow explicitly the incorporation of regulatory compacts (tariff formulae) or multi-year tariffs in concession agreements, management contracts, privatization agreements or regulatory licenses to elicit and retain investor confidence through the life of the contract or license. This, along with a provision for a recourse to international arbitration, appears to be necessary especially in the context of a judiciary with little credibility and less experience in adjudicating cases with complex sectoral disputes.

Kazakhstan's experience, thus, provides us several lessons. The obvious one is that hasty and haphazard privatization without fully thinking through the various preparatory steps and stages of reform and without a clear idea of the desired final structure would result not only in extremely poor privatization proceeds, but also in exacerbating the sector problems. The experience also emphasizes the fact (often overlooked) that the government's role after privatization does not diminish, but changes into something more complex, to achieve and sustain the benefits to the society originally envisaged. It demonstrates clearly that no meaningful competition is possible in an environment of extensive non-payment and non-cash payment. While the private sector driven by profit motives can bring in notable efficiency gains especially in such areas as metering, billing and collection and preventing theft, their interest cannot be sustained by adopting ambiguous and unpredictable tariff regulatory policies and practices undercutting their legitimate profits. Unless the government is particularly alert and prevents reintegration from the very beginning, private vertically integrated utilities will emerge, diluting the principles of competition.

Fortunately the economy of Kazakhstan has resumed growth in the context of increasing oil revenues. This could be the time to break the back of the problem of non-payment and the use of barter and offsets in the economy and enforce cash payment discipline. The spot market/balancing market is being developed to enable competition With improvements to the autonomy of the regulatory body and the substance of regulation, if necessary by amending the law, the situation could become manageable.

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KYRGYZ REPUBLIC

Introduction

With a population of 5 million and an estimated per capita GNP of $270 (in 2000), Kyrgyz Republic is one of the poorest among the former Soviet Union countries. Despite its having a highly literate population, about 64% of it is reported to live under the poverty line in 2000. Its national currency, "som" was introduced in May 1993 and its value in relation to the US dollar has fallen from 6.13 in 1993 to 49 som in 2001. It is also one of the seven highly indebted countries in the ECA region.

It is rich in hydroelectric potential estimated at 26,000 MW with an energy content of 10,000 GWh in a seasonally normal year. Only about 10% of this has been developed. Its oil reserves of 12 million tons and natural gas reserves of 6.5 million cubic meters are modest in relation to its needs. Its coal reserves estimated at 1.2 billion tones are costly to mine and only reserves of 650 million tons have been developed. Thus Kyrgyz Republic imports coal, oil and natural gas and exports electricity.[67] It releases water from its hydroelectric reservoirs for summer irrigation in the downstream counties and in return gets coal from Kazakhstan and natural gas from Uzbekistan.

System Dimensions and Characteristics

Its power system is relatively small. Its installed generation capacity of 3,532 MW consisted of 18 hydroelectric stations[68] (2873 MW) and two combined heat and power thermal plants (659 MW) at Bishkek and Osh. Construction of a further 2,260 MW of hydroelectric units (Kambarata Units 1 and 2) in the upstream of Naryn river commenced in 1989–90 under the Soviet rule, but after completing only about 30%, it was suspended for want of funds.[69]

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67. Electricity exports are mostly to Kazakhstan and partly to Tajikistan and Uzbekistan. A small export of about 5 GWh to China through a 10 kV line commenced in 1993. Exports are mostly on the basis of annual inter-governmental agreements, and partly on the basis of even shorter term contracts.

68. Most of them form a cascade in the Naryn river.

69. In May 2000 a protocol was signed between Kyrgyzenergo and two Turkish construction companies, Entes and Kanalet for completing the construction and operation of this plant at a cost of $2 billion. The Turkish companies were agreeable to invest $230 million and raise debt financing from European banks. No further progress has been reported since then.

Its transmission system consisted of 500 kV lines (545 km), 220 kV lines (1,150 km) and 110 kV lines (4,440 km). Its distribution system consists of 35 kV lines (4,301 km), 10 kV and 6 kV lines (39,980 km) and 0.4 kV lines (29,350 kms). The total transformer capacity amounted to 8,260 MVA.[70] Kyrgyz power system is a part of the Central Asian Integrated System (covering Kyrgyz, Tajikistan, Uzbekistan, Turkmenistan, and Kazakhstan) to which it provides reserve capacity and ancillary services such as frequency and voltage regulation, reactive compensation etc.

The country is fully electrified and every one has access to the grid. The total number of electricity connections in the country is about one million and more than 90% of it was for households. Total generation and domestic sales in 2000 and 2001 were about the same as in 1990, though the volumes of exports have declined (see Table 1).

Domestic consumption since 1994 is believed to be understated on account of increases in unmetered supplies and meter related problems. Domestic consumption was perhaps stable during the entire period hovering around 7800 GWh. During this period the consumption mix has undergone a major change as can be seen from Table 2.

The share of industrial consumption declined from 45.2% to 14.3%, while that of residential consumers went up from 14.5% to 54.6% - the latter figure being considered understated. This had

Table 1: Electricity Generation and Sales in Kyrgyz Republic (GWh)

Item	1990	1994	2000	2001
Gross generation	13,155	12,860	14,844	13,728
Of which: Hydro[71]	8,953	11,720	13,635	12,444
Thermal	4,202	1,140	1,210	1,284
Total Net sales	11,622	10,336	10,615	9,152
Of which: Exports-net	3,978	2,505	2,833	1,982
Domestic sales	7,644	7,830	7,782	7,169
Total System Losses	1,538	2,524	4,229	4,576
Total System Losses (%)	11.7	19.6	28.5	33.3

Table 2: Changes in Consumption Mix

	1990		2000		2001	
Item	GWh	%	GWh	%	GWh	%
Industrial consumers	3,468	45.2	1,129	14.5	1,028	14.3
Kumtor[72]	—	—	240	3.1	235	3.3
Commercial consumers	—	—	511	6.6	605	8.4
Agricultural consumers	1,913	25.3	581	7.5	454	6.3
Government Budget entities	—	—	860	11.0	938	13.1
Residential	1,111	14.5	4,461	57.3	3,909	54.6
Others	1,152	15.0	—	—	—	—
Total Domestic Sales	7,644	100.0	7,782	100.0	7,169	100.0

70. Data relates to 1996.

71. The variation in hydroelectric generation is mostly a function of water availability, rather than total demand.

72. Kumtor is a gold mining company with IFC and EBRD equity participation.

reduced the load factor of the system and increased the peak demand[73] without any noticeable increase in the sales volume.

As can be seen from Table 1 above, the total system loss[74] went up steeply from 11.7% in 1990 to an unacceptable level of 33.3% by 2001. It is believed that the losses may have been understated, to some extent, in the earlier years when there was one vertically integrated utility and that real losses became more transparent after the sector unbundling in 2001. Regardless of the reasons the losses are indeed very high. It has been estimated that out of the total losses of 33.3% in 2001, 1.6% was accounted for by auxiliary consumption of generating stations, 11.2% by losses in the transmission grid, and 18.3% by losses in the distribution network. Another 2.3% remained unexplained. About 10% is believed to be attributable to "commercial" or non-technical losses.

The reliability of the system is low and outages and load shedding are very frequent, especially in winter. Apart from the heavily overloaded transmission and distribution lines and transformers, the Government's obligations to release water from the hydroelectric reservoirs for summer irrigation in the downstream countries, force maximum generation in summer when the electricity demand in the country is lowest. During winter when demand for electricity is very high, the reservoirs have little water on account of their depletion in summer and very low inflows of snowmelt in winter. Even the two thermal stations get shut down often in winter, as foreign fossil fuel supplies are cut off, because of the inability of the utility and the country to pay the bills of suppliers promptly.

Tariffs are inadequate to cover the cash costs of operating the system, despite the fact that most of the electricity is generated in hydroelectric stations. Compared to the estimated long run marginal cost[75] of the system at US cents 2.3/kWh, the average tariff per kWh[76] of domestic sales in 2001 was only about US cents 0.9. Though the average tariff/kWh had been raised several fold in nominal local currency terms from 6.7 tyins[77] in 1994 to 45 tyins in 2001, they have tended to remain practically unchanged in US cent terms, on account of the steep inflation and devaluation of the local currency.[78] Export revenues at around US cents 1.2 to 1.3/kWh subsidizes the domestic sales. Still the overall revenues (at around 68% of the cash costs) are inadequate to cover the system costs, because of the high level of losses, poor billing, and even poorer collections. The extensive use of privileged tariffs providing tariff discounts to over 371,000 families of various categories (or a third of the total families in the country), as well as the extensive use of non-cash methods of barter and offsets to settle bills are the other causes of this sorry state.

There is a need for the government to get rid of the present policy of privileged tariffs (which subsidizes indiscriminately a large number of families which cannot qualify for such subsidies on economic grounds) and to switch over to a form of targeted social protection of the poor. Even with the proposed increase of tariffs by 25% in 2002, families with a consumption below 150 kWh per month will pay $1.14 or 1% of the average monthly household income. Families consuming 0–400 kWh per month will pay $6 or 5% of their monthly household income. However 20% of the population or 221,000 households living in what is called the extreme poverty (i.e., below the food only poverty line of 351 som/month) could be enabled to consume 150 kWh per month with a targeted subsidy of $3 million to them.

73. Peak demand, for example, went up from 1,590 MW in 1990 to 2,173 MW in 1994. Presently it is estimated at 2,700 MW.

74. Defined as the difference between the gross generation and the billed sales, in GWh.

75. The short run marginal cost of the Thermal units is around US cents 2.5 /kWh, while that from hydro units is US cents 0.3/kWh.

76. The tariffs for all consumers except residential consumers include 21% VAT. Residential consumers are exempt from this tax.

77. Kyrgyz local currency Som = 100 tyins.

78. Also, for example, the residential tariff/kWh went up from 9 tyins in 1996 to 28 tyins for consumption below 150 kWh/month and 54 tyins for consumptions of 0-400 kWh/month, and yet in US cent terms it remained at around 0.8 cents all the time.

Because of the system loss level of 33.3% in 2001, only 66.7% of the generated energy gets billed. The collections stood at 86% of the amounts billed. Out of the amounts collected, 61% was in cash or cash equivalent, 18% was in the form of offsets, and the remaining 21% was in the form of barter. If government related offsets (treated as cash equivalent) were excluded, the real cash percentage will fall to 40%. Further, Kumtor is the only customer who pays its bill fully in cash and it is paid directly to the generating company. Thus the cash available at the distribution companies is only 31% of the collections, which is inadequate to pay the generation and transmission companies for purchased power and to meet their own O&M and capital investment programs for rehabilitation.

High levels of accounts receivable (A/R) continues to be a chronic and growing problem. At the end of 1994, the A/R stood at a level equivalent to 220 days' sales. At the end of 1997 it came down to a level equivalent to 145 days' sales. Asian Development Bank documents indicated that the level of A/R declined further to 116 days in 1998 and 98 days in 1999. Since then it appears to have risen substantially again and at the end of September 2001, it stood at 2,475 million Som or the equivalent of about 10 to 11 months' sales.[79]

Structural Changes

After separation from the Soviet Union, Kyrgyz State Electric Company was formed in April 1992 to own and operate the electricity and district heat systems. Early in 1994 it was renamed as Kyrgyz National Energy Holding Company (KNEH) and operated till recently as a state owned vertically integrated national utility. Tariffs were set by the Antimonopoly Commission of the Ministry of Economy and State Property Fund (SPF managed the government holdings and their privatization.) By 1995 the government was keen to privatize KNEH as a vertically integrated utility. On the basis of an Energy Sector Review carried out by the Bank and in the context of preparing a loan in 1996 for the Power and District Heat Rehabilitation project, the Bank and other donors (such as USAID, EU etc.) persuaded the government to carry out an Organization Study under USAID assistance on the best ways of unbundling the sector and introducing competition and carrying out privatization. With the help of consultants provided by USAID and EU TACIS, the government prepared legislation to underpin the sector reform. The new Energy law was enacted on 30 October 1996 and the new Electricity law was enacted on 28 January 1997. These laws provided the basis for unbundling the sector and introducing competition and privatization of the unbundled companies, as well as for their independent regulation. Even ahead of the enactment of the said laws, a new regulatory body under the name State Energy Agency (SEA) was established by a government ordinance in 30 April 1996 to license electricity businesses, regulate tariffs, promote competition and to issue and enforce market rules. The government corporatized KNEHC by registering it as a Joint Stock Company (JSC) and auctioning off 4.5% of the shares in a national voucher program. The government held 80.5% of the shares through SPF, and the remaining 15% was owned by the Social Fund and the employees. SEA was made responsible to institute and monitor a performance agreement between the SPF and KNEHC. The government also initiated the process of unbundling the sector with the aim of privatizing the first distribution company on a pilot basis before the end of 1999.

However, the government maintained throughout the process a skepticism of unbundling and privatization and showed a great deal of hesitation in moving forward. After a great deal of discussions between the Bank, other donors and the government, in the context of processing the Consolidated Structural Adjustment Credit (approved in September 2000), the government agreed to approve the concept of unbundling for the release of first tranche, identify the Distribution company to be privatized for the release of second tranche, and commence negotiations with the selected strategic investor for the sale of majority shares in that company for the release of the third tranche. Thus four distribution companies were separated from KNEHC in January 2001, and by September the generation and transmission companies were also separated. Thus KNEHC was unbundled into

79. The A/R at the level of 4 discos seems to be only 144 days' sales, as seen from Table 3.

TABLE 3: THE FEATURES OF THE FOUR DISTRIBUTION COMPANIES IN 2001

Item	Sever elektro	Vostok elektro	Osh elektro	Jalal-Abad elektro
Energy purchased GWh	4602	1862	2099	1121
Energy Sold GWh	3359	1523	1469	818
System Losses (%)	27	18	30	27
Total domestic revenue (million som)	1373	683	438	315
Collection ratio (overall) (%)	90	90	73	89
Residential collection rate (%)	60	54	51	68
Percentage cash in collection	51	74	66	44
A/R as at the end of September 2001 (million som)	548	195	443	102
Average Tariff/kWh billed in Tyins	45	50	41	43

six electricity sector JSCs,[80] one each for generation and transmission and four for distribution. JSC Electric Stations had the responsibility for all hydro and thermal generation units. JSC National Electric Network had the responsibility for operating the transmission grid and for load dispatch. JSC Severelektro handled distribution in Bishkek, Chu and Talas oblasts. JSC Vostokelektro handled distribution in Naryn and Issyk-kul oblasts. JSC Oshelektro and JSC Jalal-Abadelektro handle distribution in Osh and Jalal-Abad oblasts respectively. All six have their own legal identities, Boards, management and staff and are regulated by SEA.

The relative size and conditions of operation of the four distribution companies could be gauged from Table 3.

Under the revised arrangements, the distribution companies purchase electricity directly from the generating company on the basis of a standard one year Power Purchase Agreements (PPAs). The transmission company will not buy and sell electricity in the domestic market. It will only transmit electricity and charge the transmission fees from the distribution companies on the basis of a standard transmission agreement concluded with them. The transmission company will dispatch the system on the basis of the contracts between the generation and distribution companies and balance the system mainly on the basis of imports and exports. It will also be responsible for the provision of ancillary services to CAIS. The SEA is in the process of finalizing and approving key market documents such as the PPA, Grid Code, Market Rules and Licensing Documents with consultant assistance. The consultants appointed to assist SPF to privatize Severelektro are expected to finalize soon the mini-prospectus for circulation to potential strategic investors.

At present, there seems to be not much scope for competition, since one generating company is selling to four distribution companies. The nondiscriminatory third party access (TPA) to the transmission and distribution lines is yet to take root to enable at least the large industrial consumers to buy directly from the Generation company on the basis of bilateral contracts. Currently the Bank has suggested to the government that even consumers who now get supply directly through 110 kV lines should be regarded as buyers from the distribution companies and not allowed to buy directly from the generators. While such a move would make the privatization of the distribution company a little more attractive, it would run counter to the philosophy of consumer choice driving competition. The whole exercise would be meaningful only when there are several generating companies and when at least the large industrial consumers in addition to the distribution companies can buy directly from the generating company of their choice. And a well understood TPA underpinned by nondiscriminatory tariffs for wires services would be a necessary pre-condition for that. One may assume that the reform had been designed on this

80. Actually, a heat distribution company in Bishkek was also separated at the same time.

basis and would proceed in the future on this basis, though at present the existence of these elements is not evident.

The government continues to be hesitant about the reform involving unbundling and privatization. Even recently Prime Minister Bakier expressed himself against privatization and declared that there is no question of government ever parting with the Toktogul Hydroelectric facilities.

Given the present bleak outlook of the potential strategic investors towards investments in the emerging markets, it is doubtful whether the mini prospectus to be issued for Severelektro would elicit any response at all. The overall size of the power system in Kyrgyz Republic is too small to enable the introduction and sustenance of any meaningful competition. Even the largest of the four distribution companies Severelektro is quite small with total sales of 3359 GWh and an annual revenue of $28 million is too small to attract the attention of anyone in the strategic investment community.

This has to be considered in the context of country problems and sector problems yet to be resolved to attract strategic investors. Given the level of poverty and the remoteness of the country, its highly indebted status, the continued and persistent use of barter and offsets rather than cash for transactions in the economy, the long distance it has to go to evolve acceptable legal systems, complicated property rights, and reliable enforcement mechanisms and to achieve a semblance of macroeconomic stability with moderate inflation, one wonders whether the move towards unbundling, privatization and competition would be regarded by some as premature and somewhat inappropriate. In order to recover even a small portion of the sums invested in the sector, the present intolerably low level of cash flows in the sector has to be improved by focusing on: (i) improving the level of tariffs at least to cover the cash costs of operating the system; (ii) improving the structure of tariff to remove cross subsidies; (iii) eliminating the present privileged tariff system and replacing it with a meaningful state subsidy targeted only to the families categorized as being under extreme poverty; (iv) reducing the non-technical or theft losses; (v) getting rid of the practice of accepting barter, offsets and other non-cash forms of payment; (vi) sharply improving the meter reading, billing procedures and the level of collections and cash collections; and (vii) reducing the level of accounts receivables to reasonable levels of 60 to 75 days' sales equivalent. If these actions are undertaken and the tariff policies clearly enunciated, serious investors might be attracted to the sector, and may make reasonable offers. Without doing these things, the government may have to reconcile itself to selling the assets at throw away prices, if a buyer turns up at all.

Unbundling may have been premature and may have increased transaction costs, especially in a country with a small pool of trained practitioners of market mechanisms with financial, commercial, accounting, and auditing skills, in the absence of benefits flowing from competition. However, some benefits such as greater transparency, greater management focus on distribution problems and investment have been mentioned and may well be true. Even at this stage, it is good to focus on the utility reform (incorporating the elements mentioned above in the previous paragraph and the obvious ones such as modern accounting, audit and disclosure procedures) aimed at making the six unbundled companies operationally sound and financially viable to a level at which they will cover all their costs and raise internally generated cash to cover at least 20 to 25 % of the cost of their rehabilitation needs and be capable of raising the remaining 80 to 75 % as commercial debt. Attempts to sell them at that stage is likely to meet with reasonable success.

Meanwhile the country has a great deal of hydroelectric potential with relative cost advantage and the adjoining country China is a potential lucrative export market. The international donor community could perhaps concentrate on how to interest investors in setting up new hydroelectric projects exclusively for export based on long term guaranteed export contracts somewhat on the lines such projects have been piloted say as in Laos. They could help the government to take equity positions in such ventures and look for income by way of dividends and royalties, and corporate taxes on profits.

Alternatives such as Management contracts, leasing arrangements and inter utility cooperation could be thought of to improve the performance of the six companies, in the short term. A sugges-

tion had been made that investors could come in first as lenders, with a right to convert their debt into equity, should the utility improve under their management. This is to be enabled using the partial credit guarantee mechanism of the Bank. This has several aspects, such as adding a debt burden to a highly indebted country, government's willingness and ability to abide by the arrangements, the legal implications of the Bank nominating a member on the Board of the company and members in the regulatory body etc., that need to be examined carefully. Other similar innovative methods with which private investment could be attracted need to be thought of.

The obvious lesson from the Kyrgyz experience is that the standard model of unbundling and competition through a pool-like mechanism and privatization to strategic investors may not be the best and the most practical choice in all countries, especially in countries with small power systems. For systems such as those in Kyrgyz Republic, alternative methods of securing private investment in the sector have to be explored.

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LITHUANIA

Introduction

Lithuania is a small country with a homogenous population of about 3.6 million people. Its politics has become firmly democratic and its economy is becoming increasingly market driven. After the contraction of GDP in the first half of the 1990s, growth has resumed since 1995. GDP growth in 1995 constant prices during the period 1994–2000 (though somewhat uneven[81]) was at an average annual rate of 3.3%. The GDP growth in 2001 is reported at 5.7%. Inflation had been effectively controlled and has been maintained at a modest annual rate of about 2% over the 1999–2001 period. Current account deficit was contained at around 3.3% of GDP and direct foreign investment in the first nine months of 2001 amounted to $183 million. The exchange rate had remained stable at the rate of four Litas to a US dollar over the last several years on account of the Currency Board arrangement linking Lithuanian currency to the US dollar. Lithuania is one of the ten countries expected to achieve EU accession by 2004.

System Dimensions and Characteristics

Installed Generation Capacity

Lithuania's indigenous fuel resources are very modest and it is substantially dependent on the oil and gas imports from Russia to meet its energy needs. The electricity system in Lithuania was designed to meet primarily the demands of the north-west Soviet Union and not to meet merely Lithuania's own demand. After the collapse of the Soviet Union, Lithuania's system became characterized by excess capacity. The total installed electricity generation capacity at the end of 2000 was reported as 6,557 MW, consisting of Ignalina Nuclear Power Plant (2 × 1,500 MW), one large thermal power plant at Lietuvos (1,800 MW), four combined heat and power (CHP) plants (767 MW), one pumped storage hydropower plant (4 × 200 MW),[82] one medium sized run-of-

81. The decline in growth in 1999 was a consequence of the Russian crisis of 1998.
82. There is a provision to add another 800 MW in the second phase of this pumped storage unit. However, with the impending closure of Ignalina, this extension is not expected to take place.

river hydro plant and several smaller sized hydro electric units (114 MW) and several small thermal power units owned by sugar mills and other industries as captive generating units (76 MW). For safety reasons, the Ignalina Nuclear plants units have been de-rated as 2 × 1300 MW. Other units have also been de-rated to some extent on account of age. The total available capacity at the end of 2000 was reported as 5,999 MW, which is more than 3 times its system peak demand of 1,780 MW in 2000. The peak demand had declined considerably from the level of 3,070 MW in 1990.

The EU has been persuading the Lithuanian government to shut down the nuclear plant on grounds of safety. The parliament approved in May 2000, the decommissioning of unit 1 by 2005. Decision on the timing of closure of Unit 2 would be announced at the time of the parliament approving the revised Energy Strategy due in 2004. The EU has indicated to Lithuania that it would like the unit 2 to be closed by 2009. Though no new capacity needs to be added through 2010 on account of the closure of units 1 and 2, further investments of roughly $500 million would be needed to rehabilitate and retrofit the other thermal plants in that context.

Transmission and Distribution

The transmission system consists of 1,598 km of 330 kV and 4,419 km of 110 kV lines. There were eleven 330/110 kV substations with a total capacity of 3,240 MVA and 199 110 kV substations with a total capacity of 5,497 MVA (as of January 1999). There is also a 750 kV line to transmit power from the nuclear plant to Belarus. The system has good interconnections to Latvia and Belarus and Kaliningrad of Russia. There is a continuous electricity interchange by way of imports and exports among these countries. Since 1992, the three Baltic countries have set up a jointly owned dispatch center called DC Baltija to coordinate the parallel operation of the three systems. In February 2001, Lithuania signed a multilateral agreement with Estonia, Latvia, Russia and Belarus, to enable Lithuania to export power through Belarus to other countries such as Slovakia. The Energy Strategy of 1999 stresses the importance of linking the Lithuanian power system to that of Poland and those of West Europe. The proposed transmission link to Poland has not been agreed to as the economic viability remains uncertain. In addition, concerns have been has expressed about the possible environmental impact of building an HV transmission line in northeastern Poland. Furthermore, Poland has not yet opened up its electricity market to competition from outside sources of electricity supply.

The primary distribution voltages are 35 kV to 6kV and the secondary distribution is by 0.4 kV lines. The distribution network until recently consisted of seven regions and serves about 1.3 million consumers. Geographical coverage of the system is complete and everyone in the country has access to the grid.

Energy Generation, Supply, and System Losses

Peak demand, energy generation, net exports, and net domestic consumption have all declined substantially from the levels in 1989, as can be seen from Table 1. Consultants engaged for the study of the Baltic Regional Energy Development Program have estimated that under a high GDP growth scenario (5 to 6% p.a.) Lithuania's total electricity consumption would reach 16.9 TWh and its peak demand would reach 3,338 MW by the year 2015. Under a lower GDP growth scenario (3% p.a.) the total energy consumption would reach 13.3 TWh and the peak demand would reach only 2,660 MW by 2015.

Auxiliary consumption is rising on account of the age of generating units and the need for rehabilitating and retrofitting them. Network losses have also risen for the same reason in relation to the lines and transformers. Network losses at the transmission level (330 kV) seem to be declining compared to distribution losses (See Table 2).

In 2000, industry and construction had the largest share of total consumption (37.4%) followed by commercial and public service (29.8%), households (28.5%), agriculture (3.1%) and Transport (1.2%). The pattern has remained largely unchanged over the last six years.

TABLE 1: GENERATION, CONSUMPTION AND LOSSES IN ELECTRICITY (electricity in TWh)

Item	1989	1998	1999	2000
Gross Generation	29.16	17.63	13.54	11.43
Auxiliary Consumption in TWh [83]	2.13	1.75	1.63	1.42
Auxiliary Consumption (%)	7.3%	9.9%	12.0%	12.4%
Net Exports	12.13	6.08	2.68	1.34
Energy used by the Pumped Storage Plant	—	0.65	0.62	0.43
Total Electricity Consumption	14.90	9.15	8.61	8.24
Network Losses in TWH	1.64	1.52	1.33	1.28
Network Losses (%)	11.00%	16.6%	15.4%	15.5%
Net Domestic Electricity Consumption	13.26	7.63	7.30	6.96
Peak Demand (MW)	> 3000	2,080	1,920	1,780

TABLE 2: NETWORK LOSSES AT THE TRANSMISSION AND DISTRIBUTION SEGMENTS

Item	1998	1999	2000
Losses in 330 kV system GWh	375	343	290
Losses in 330 kV system (%)	4.09	3.98	3.52
Losses at 110 kV and below GWh	1,144	987	991
Losses at 110 kV and below (%)	12.5	11.46	12.02
Total network losses GWh	1,519	1,330	1,281
Total network losses (%)	16.6	15.4	15.5

The Annual Report of Lithuanian Power Company for the year 2001 reports that energy generation in 2001 rose to 14.6 TWh (or by 28% from that in 2000), driven largely by increased exports (4.2 TWh or 3 times larger than in 2000[84]) and to some extent by the increased domestic sales, reported at 7.2 TWh. Thus for the first time in the last few years generation, export and domestic sales registered growth, reflecting a significant economic upturn. Industry and construction had a share of 38% in total sales, followed by commercial and public services and transport (35%), residences (25%) and agriculture (2%). Per capita electricity consumption in Lithuania reached 3000 kWh in 2001.

Exports and Imports

Interchange of power among Lithuania, Latvia, Belarus and Kaliningrad of Russia takes place regularly. Because of the high excess capacity and the base load operation of the Ignalina nuclear plant in Lithuania, it generally manages to achieve substantial net exports. Belarus, the main importer of power from Lithuania, however often had not paid for the import in a timely manner. Exports to Belarus, among other things, also contributed to the high levels of accounts receivable of LPC creating serious liquidity problems and forcing LPC to borrow in the short term markets. Lithuania thus often found it necessary to discontinue supplies in order to collect arrears and dues from Belarus until a revised arrangement was put in place in 2001. Thus the volume of exports fluctuates

83. Including small amounts used for Electric boilers.

84. In 1999 Lithuania decided to cut-off exports to Belarus over problems with persistent non-payments. An agreement was reached in 2001 to restore these exports through a Russian supplier, while considerably reducing the non-payment risk to Lithuania. However, the export price agreed to is reportedly much lower than in the past.

TABLE 3: AVERAGE ELECTRICITY TARIFFS IN LITHUANIA
(in US cents /kWh)

Item	1995	1996	1998	1998	2000
Industrial consumers	3.29	3.45	3.54	3.53	4.00
Residential consumers	3.95	4.21	4.17	4.12	5.17
Agricultural consumers	n.a.	n.a.	3.70	3.65	4.95
Others	4.00	4.38	4.20	4.30	5.33
Average tariff for domestic sales	n.a.	n.a.	3.88	3.88	4.66
Average tariff for export sales	n.a.	n.a	2.06	2.06	1.60

from year to year. In the year 2000, Lithuania imported a total of 5,150 GWh of electricity from Latvia (2,955 GWh) Belarus (2,107 GWh), Russia (88 GWh). In the same year it exported 6,486 GWH of electricity to Russia (2,889 GWh), Belarus (1,981 GWh) and Latvia (1,616 GWh). The net exports declined from the level of 11.97 TWh in 1990 to 1.34 TWh in 2000. However, in 2001 net exports from Lithuania registered a remarkable increase and reached the level of 4.2 TWh. The exports were to Belarus (2.1 TWh), Latvia (1.1 TWh), Kaliningrad (0.8 TWh) and Estonia (0.2 TWh). Increased exports became possible because of multilateral agreements with Russia, Belarus and other countries and improved liquidity in the importing countries. The website of LPC further reports that in January–April 2002 the net export was 2.642TWh some five times larger than in the same period in 2001.

Tariffs

During the period 1990–1997, the Lithuanian Power Company was handling both the electricity and heat businesses. This was also the period in which GDP contracted, inflation was very high and the prices of imported fuels quickly rose to world price levels. The government could not adjust the electricity and heat tariffs in a timely manner to keep pace with the rising costs. The problem of uneconomic pricing was more acute in the heat sector. While there was some degree of cross-subsidization between electricity and heat, the principal result was that LPC accumulated financial deficits, which had to be cleared by the government through the grant of production subsidies. There were also distortions in the electricity tariffs in that the industrial consumers were subsidizing the residential consumers. With the resumption of growth, and control over inflation, the government managed to give up production subsidies, correct the tariff structure and levels (adopting the principle of full cost recovery[85]) and also transfer the heat assets and heat business from LPC to the municipalities. The process of tariff setting was sought to be de-politicized by the appointment of an autonomous regulatory body[86] in 1997. Thus by 1996 the average electricity tariff for industrial consumers stood at US cents 3.5/kWh, while that of residential consumers reached US cents 4.2/kWh. The overall average tariff/kWh for domestic sales stood at US cents 4.66 during 2000, as a result of 20% tariff increase with effect from 1 January 2000. These tariffs remained unchanged in 2001, but were increased by 5% at the beginning of 2002.

The export tariff is for the sale of power at 750 kV and it declined as a function of the difficulty of finding buyers who can afford to pay for the power bought. Belarus, the main importer could not pay and supplies had to be discontinued for non-payment. The average revenue from exports would appear to have gone down further[87] to about US cents 1.25 in 2001. The level and structure

85. The full cost recovery principle based tariffs came into effect from July 1997.
86. The Energy Price Commission was reconstituted under the Energy law in November 1996. The formal name of the body is National Control Commission for Prices and Energy.
87. Based on net exports of 4.2 TWh and overall export receipts of Lita 209.9 million reported the Annual Report 2001 of LPC.

TABLE 4: THE ELECTRICITY ACCOUNTS RECEIVABLE SITUATION IN LITHUANIA
(expressed in equivalent days' sales)

Item	August 1996	April 1997	September 1997	December 1997
All Classes of Consumers	42	—	13	13
Government Budget Entities	153	82	32	—
Municipalities	284	86	21	—

of tariff in 2000 and 2001 appear to be reasonable and need to be adjusted from time to time to keep abreast of the changing costs.[88] Tariffs are differentiated by voltage levels and time of use. In the case of larger consumers there are demand charges and energy charges.

Non-Payment and Arrears

During 1990–97 serious non-payment problems and significant inter-enterprise arrears emerged, as a result of GDP contraction, fiscal deficits, high inflation, low money supply to control inflation, collapse in industrial production, rise in the cost of imported fuels, and the significant decrease of traditional export markets. The problem was much more severe in the heat business. LPC, which handled both electricity and heat businesses at that time, had significant accounts receivables for electricity and heat from households, government budget entities (GBEs), municipalities and municipal budget entities (MBEs) and in turn built up arrears to fuel suppliers and government. The foreign fuel suppliers were threatening to curtail and cease supplies. Under the adjustment lending conditionalities of the Bank and the Stand-by Agreements with IMF, the government pursued a set of determined actions: to make it easier for the utility to disconnect supply for non-payment, to clear the arrears of GBEs, to prevent them from accumulating fresh arrears, and to settle directly the dues of LPC from municipalities and MBEs from the state budgets (using the amounts payable to the municipalities). The government also transferred in 1997 the heat assets and heat business to the municipalities. By these measures the accounts receivables situation was brought under control (see Table 4), and the inter-enterprise arrears problem was overcome.

Structural Changes

Corporatization and Regional Integration

The Lithuanian Power Company[89] was a fully government owned state enterprise, which owned and operated all the generation, transmission and distribution assets of both electricity and heat businesses (except the Ignalina nuclear power plant) as a vertically integrated utility. The nuclear power plant was a separate SOE, which sold all its production to EPC. These two enterprises were treated as special enterprises, permitting a greater level of state intervention in their operations than in the case of normal SOEs. LPC had several subsidiaries for generating units, one for transmission and dispatch, seven for electricity distribution and six heat businesses in the various regions. Though called subsidiaries they acted like divisions of one large company and there was only one consolidated financial statement for LPC. In the context of the government moving over to the concept of full cost recovery tariff, minimization of cost became an objective and to enable this, the government corporatized various energy entities including LPC and registered it as a joint stock company in 1997 under the name "AB Lietuvos Energija". The government owned 86.5% of the

88. Based on these tariffs LPC indicates in its Annual Report a 9.8 % return on equities, and a 6.5% return on assets in 2001. Its debt/ debt + equity ratio was 30.7%.

89. Though the Bank, EBRD and bond rating companies called this institution by the name LPC, its official name was Lithuanian State Power System (LSPS). In Lithuanian language it was called "Lietuvos Energija".

shares, 5% was owned by Vattenfal - a Swedish utility company - and the remaining 8.5% of the shares belonged to workers as a result of the voucher privatization program[90] .

Given the small size of the Lithuanian power system (1.3 million consumers and a peak demand of less than 2000 MW), it would not, prima facie, be considered suitable for sector reform involving unbundling, introduction of competition and privatization of the fragmented small entities. Furthermore, the capacity of Ignalina nuclear plant alone is 50% larger than the peak demand and this would not allow any meaningful competition from other generating units. However the Lithuanian system is well integrated with those of its Baltic partners, Latvia and Estonia. All three systems are also well connected to those of Belarus and Russia. All three Baltic countries are actively seeking accession to EU and are pursuing a project to connect the Baltic system to that of Poland and from there to those of West Europe. In addition, a DC link from Estonia to Finland is being considered to close the Baltic transmission ring. Though each of the three Baltic countries has a small electricity market, combined together they have a market dimension suitable for the type of reform mentioned, and appropriate for EU accession. The Common Baltic Electricity Market (CBEM), would have an installed capacity exceeding 11,500 MW, a peak demand in excess of 4,500 MW and an energy consumption in excess of 24 TWh and a large export capability. Nuclear capacity of Lithuania, oil shale based thermal capacities of Estonia and hydroelectric capacities of Latvia would complement one another. These countries also jointly own a regional dispatch center to coordinate the parallel operations of their systems. It is in this context that Lithuania decided to adopt reforms involving unbundling of the sector, introducing competition and privatization.

Commercialization and Preparatory Steps

However, unlike Ukraine and Kazakhstan, Lithuania did not rush into such a reform and premature privatization. Instead, it utilized the second half of the 1990s (with moderate GDP growth and relatively moderate inflation) to stabilize its electricity system and prepare it fully for the envisaged reform, while at the same time trying to secure political consensus on the content and direction of reform. Such preparatory steps taken and measures adopted by the government include:

- Determined action to clean up the mess created by non-payment and inter-enterprise arrear problem and enforce payment discipline (1996–1999);
- Incorporation of LPC as a joint stock company to be operated on commercial principles (1997);
- Separation of the heat assets and business from LPC and transferring them to the municipalities, thereby freeing LPC from the need to cross subsidize heat business (1997);
- Adoption of a more rational approach to export of electricity and curtailing supply to those importers (such as Belarus) when they do not settle the bills;
- Changing over from the policy of keeping end user tariffs low and providing production subsidies to LPC to the policy of allowing full cost recovery tariffs, and setting up an autonomous tariff regulatory body for this purpose (1997);
- Enabling legitimate tariff increases based on justified costs plus formula, while at the same time focusing on least cost supply through the adoption of efficiency measures such as: (a) introduction of IAS based accounts for LPC, and internal and external audits of its accounts, (b) introduction of management performance audits of LPC, and (c) appointment of a supervisory board for LPC and reducing state intervention in LPC's day-to-day operations;
- Organizing in LPC, business units by function (i.e., generation, transmission and distribution), and treating them as profit centers with their own balance sheets (July 2000) to enable eventual unbundling of LPC;

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90. Originally about 10% of the shares were given to workers. When the district heating business was separated from LPC and given to the municipalities, many individuals preferred to keep their holdings in LPC. Vattenfall appears to have bought the shares from private individuals first up to five percent and later up to about 10.5% and since sold them on Energie AG. The website of LPC reports shares of government at 85.7%, shares of E.on Energie at 10.9% and shares of Lithuanian private shareholders at 3.4%.

- Enabling LPC to overcome its liquidity problems through a restructuring of its debts;
- Improving the quality of the supervisory Board of LPC, by appointing outside experts in law, accountancy, and business as directors on the Board; and
- Improving the corporate governance of LPC by clearly defining the roles of government, the supervisory Board, and the executive Board of the company, and giving the latter adequate autonomy of operation to achieve the objectives and performance targets set by the government and the supervisory Board.

Through a set of efficiency improvement measures, the financial statements of LPC and its disclosure procedures improved to an extent that they enabled LPC to access the debt markets on the basis of its balance sheets and financial projections. Thus it was able to successfully restructure its debts by lengthening maturities to match the useful life of the assets. Its credit rating[91] also improved and its cost of borrowing dropped from a spread of in excess of 450 basis points over LIBOR in 1999 to 75 basis points over LIBOR in 2001.

Policy and Legislative Actions

The government's Energy Strategy of October 1999, approved by the parliament in early 2000, enunciated the objective of pursuing "free competition and open energy markets within and outside the country". The key components of this overall strategy were: (i) reliable, safe and least cost energy supply; (ii) energy efficiency enhancement; (iii) energy sector management improvement and implementation of market economy principles; (iv) minimization of environmental damage and assurance of nuclear safety; (v) integration of the Lithuanian energy sector with those of the EU; and (vi) regional cooperation and collaboration. Based on this strategy the Energy Law of 1995 was amended in March 2000. A new Electricity Law was passed in July 2000 and further amended in December 2000. These laws enabled the unbundling of the electricity sector, the introduction of energy trade based on bilateral contracts between the generators and eligible consumers, and nondiscriminatory third party access to the transmission and distribution services. Eligible customers can choose their suppliers and contract with them on the terms of supply and the price. Thus the price of electricity escapes regulation and is determined in the market through bilateral negotiations. Since the implementation of this concept needs a range of metering facilities and control mechanisms, the government adopted a phased program of implementation. Thus it was decided that with effect from July 1, 2001 all consumers with a consumption of 20 GWh or more would be declared as eligible customers. By January 1, 2002 all consumers of 9 GWh or more would become eligible consumers and by January 1, 2010 all consumers in the country would become eligible consumers and have a choice regarding their supplier. On account of a six month delay in the related law becoming effective, the above schedule has been pushed back by six months. Thus as of January 1, 2001, twelve consumers with a consumption of 20 GWh or more were declared as eligible customers free to choose their supplier. Thus 21% of the market by sales volume or 1,775 GWh was covered by this market opening.

Sector Unbundling

Following a model consistent with EU Directive 96/92, generation and distribution business units were separated from LPC and the following five legal entities (joint stock companies) came into existence and started operating independently[92] on January 1, 2002. These are:

- LPC or AB Lietuvos Energija, which now had the transmission system, the dispatch center, as well as the Pumped Storage hydroelectric plant (800 MW) and the Kaunas Hydroelectric plant (100 MW) for system control and frequency and voltage regulation;

91. PC website indicates that Standard & Poor has given to LPC a rating of BB+ for corporate long term, that Moodys has rated it as Ba1 for long term and that Fitch IBA has given it B for short term and BB+ for long term.

92. The assets, liabilities and staff of the former LPC have been appropriately divided among the five entities based on detailed work done with the help of consultants engaged by LPC in the context of the policy dialogue under SAL II of the Bank, during the last 12 to 15 months.

- AB Lietuvos Elektrine, which owns and operates the 1800 MW steam turbine generating unit;
- AB Mazeikiai Elektrine, which owns and operates the 194 MW CHP unit;
- AB Rytu Skirstomieji Tinklai, which owns and operates the eastern electricity distribution system covering four of the seven former distribution units, namely, Vilinius, Panevezys, Alytus, and Utena (It serves 673,327 consumers);
- AB Vakaru Skirstomieji Tinklai, which owns and operates the western distribution system covering the remaining three former distribution units (It serves about 630,000 consumers).

LPC (in its new form) will thus essentially be a Transmission System Operator and will also handle the dispatching responsibilities. For the time being it will also act as the Market Operator and a licensed Exporter of electricity. Eligible consumers and the two distribution companies will choose their supplier (from among the nuclear plant, the two generation companies mentioned above, and the several municipal CHP companies or any of the licensed independent suppliers or electricity traders) and conclude bilateral supply contracts. Dispatch will be on the basis of these contracts and TSO would balance the dispatch with the hydroelectric units at its disposal and the export and import orders. Eligible consumers may also buy capacity and energy in auctions conducted by the Market Operator. Other consumers will get their supply from the two distribution companies, which are called the public suppliers. The Grid Code and Market regulations have been finalized and are being implemented from January 2002 gradually.

Regulatory Improvements

The regulatory agency[93] as reconstituted in 1997 had the responsibility only to regulate tariffs. In the context of the sector reform, its role has become more comprehensive including such aspects as licensing of power sector activities (generation, transmission, distribution, independent supplier/trader, imports and exports of electricity), enforcing the conditions of license, declaring a particular customer as eligible or otherwise, dispute resolution, enforcement of grid code and market regulations etc. The price of electricity will no longer be regulated unless the producer happens to have more than 25% share of the market. Transmission and distribution tariffs will be regulated. The tariffs for sale of electricity for captive consumers of distribution companies would also be regulated. All tariff regulation will be on the basis of price caps using the RPI-X formula aiming at efficiency gains in three year periods. The current price of transmission and distribution services at roughly $5/MWh and $20/MWh, respectively, enable a reasonable return on assets and do not create an artificial barrier to entry for electricity trade[94]. Competent persons with a good standing have been appointed (by Presidential Decree) as Members of the regulatory Commission, which has evolved transparent procedures in a short time. The Commission enjoys considerable autonomy and has been provided with adequate resources.

Poised for Privatization

The government is thus well poised to undertake the privatization of the unbundled utilities. The plan is to privatize first the two distribution companies offering 51% of the equity to a strategic investor selected on the basis of international competitive bidding. The government has already recruited privatization advisors on the basis of ICB using its own resources[95]. This would be followed by similar privatization of the two generating companies, which the Government may undertake at the same time as distribution privatization. As of now the intention is to keep the transmission company in the public sector. While the preparation of the sector for privatization had

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93. Its formal full name is National Control Commission for Prices and Energy.

94. A recent report by the EU indicates that the Lithuania price for transmission and distribution services is about the same as the average for EU countries.

95. This contract appears to have been terminated in November 2002 on account of disagreements between the parties to the contract on the fees payable.

been thorough and orderly, the effort comes at a time when the investor interest in emerging markets is at the lowest ebb on account of Enron and Anderson debacle and the falling stock values of investors involved in emerging markets. Also in the context of the continued operation of the nuclear units, the two generating companies could not hope to sell much power, and may primarily provide system reserve requirements and ancillary services to the grid. The investor interest in these assets may be low. The government may have to treat one or both of them as stranded assets[96] and devise methods of recovering the related stranded capacity cost from the consumers. Given the political stability and maturity, and the environment of economic growth and the extensive preparation and meaningful sector reforms undertaken, the distribution privatization should attract investor interest from European strategic investors, despite the world financial environment.

Even if the privatization effort does not succeed now, it can always be taken up later at an appropriate time. The country has a sector structure with consumer choice at least for the larger consumers and an electricity market with appropriate regulation to ensure supply to the customers on an efficient basis. The sector structure and arrangements conform to the EU directives and should help EU accession. The key lesson from Lithuanian experience is that patient and orderly improvement measures to obtain the best results in the vertically integrated structure and then to undertake unbundling and introduction of competition to gain further incremental sector efficiencies is the optimal approach from the long term interests of the public, as it protects the public from needless trauma arising from ill planned, sudden and disruptive reforms (as was done in some FSU countries).

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96. The Mazeikiai Power Plant is considered to be particularly susceptible to becoming a stranded asset if the nearby refinery does not continue to purchase waste heat. However, its long-term debt can be pre-paid from Q1 2002 profits, thus limiting its liabilities.

MOLDOVA

Introduction

With an area of 33,700 square kilometers, Moldova is the second smallest country among the former Soviet Union states. Located in between Ukraine and Romania, it has a population of about 4.3 million people and a per capita GDP of $370 (1999). It became independent in August 1991, but soon armed conflict between the regions on the right and left sides of Nistru river resulted in the region on the left, Transnistria[97], declaring itself independent of Moldova. During 1991–1996, the country's GDP contracted by 60% Modest growth, resumed in 1997, was reversed in the next two years largely on account of the Russian economic debacle. Modest growth again resumed in 2001 and slightly accelerated in 2002. Presently GDP is believed to be about 43% of what it was in 1991. Annual inflation rate, which rose to 2,700 % in 1993, came down to 11.7% in 1997, but shot back to 40% and 27% in the next two years. It was around 15.4% in 2001.

Moldova is heavily dependent on imports for meeting its energy needs. It imports all of its natural gas needs (about 1.2 billion cubic meters/year) from Russia, most of its oil products needs (300,000 to 400,000 Tons/year) from Russia and elsewhere, and more than 75% of its electricity needs (about 3.2 TWh/year) from Ukraine, Romania and Transnistria. The value of its annual energy imports exceeds 35% of the total value of all imports. The steep rise in the energy import prices, following the collapse of Soviet Union, and the failure of the government to pass on to the consumers such increases fully and in a timely manner led to large quasi-fiscal deficits of about 5% of the GDP. The country was thus caught in the trap of rising external debts and internal arrears. Reforms, helped by donors, were aimed at escaping from this situation.

System Dimensions and Characteristics

With a total installed power generation capacity of about 422 MW, a system peak demand of about 700 to 750 MW and an annual energy consumption of about 3.2 TWh, Moldova's power system

97. The situation of this region, populated mostly by people of Russian origin, remains unresolved from 1992, with Russian troops still stationed there.

is very small. Its installed generation capacity consists of one hydro power plant (16 MW) and three combined heat and power plants (314.4 MW) and several power stations in sugar factories (92 MW)[98]. The Transnistria region has a large thermal power plant (2520 MW) and a hydroelectric plant (45 MW). The annual electricity consumption is of the order of 3.2 TWh and in 2000, for example only 23% came from local power stations, while 22% was imported from Transnistria, 47% from Ukraine, and 8% from Romania.

Moldova operates a transmission system consisting of 214 km of 400 kV lines, 274 km of 330 kV lines, 2,986 km of 110 kV lines, and 1,830 km of 35 kV lines. Also, a 750 kV line passes through Moldova connecting Ukraine to Romania and Bulgaria, but it is not connected to the Moldova power system. The total transformer capacity is about 5300 MVA. Interconnections to the adjoining countries include: (i) one 400 kV line Bulgaria; (ii) three 110 kV lines Romania; (iii) seven 330 kV lines and several 110 kV lines to Ukraine enabling parallel operation of the two systems. The transmission losses at around 4% are considered reasonable since the system also includes 35 kV lines[99].

The distribution network is extensive (a total of about 58,763 km of low voltage lines) and more than 98% of the population has access to electricity. The distribution system is divided into five regions, namely the Capital, Central, South, North and North-West. Distribution losses are very high at around 35%, a great deal of which is attributable to theft and meter tampering.

Following the GDP decline, electricity generation and demand also declined since 1991. In 1991, the country including Transnistria produced 11.9 TWh, while production dropped to 3.2 TWh by 2000. Excluding Transnistria, the production in the rest of the country dropped from 1.3 TWh to 0.7 TWh. Consumption in Moldova (excluding Transnistria) declined from 5.5 TWh in 1991 to 3.1 TWh in 2001. A recent least cost power development study prepared for transmission planning suggests that the peak demand would grow at the annual rate of 3.9% during 2002–2005, accelerate to 6% during the next five years and fall back to 3% in the following 10 years.

Structural Changes

Till 1997, Moldenergo was the state owned vertically integrated utility responsible for generation, transmission and distribution of power and heat in Moldova. Its financial viability was totally eroded during 1991–1997 on account of declining demand, rising fuel and electricity import prices, tariffs which could not keep pace with rising costs, steep inflation and devaluation of local currency, inability of consumers to pay even the low tariffs, high levels of system losses exacerbated by extensive power theft and corruption, low levels of collection and very percentages of cash collection,[100] high levels of accounts receivable, and accounts payable. Its inability to pay the import bills resulted in the supply being curtailed and system security becoming fragile. Extensive load shedding became a daily routine all over the country for nearly a decade.

Based on the advice of the Bank and other donors such as USAID and EBRD, the government embarked on a sector reform involving: (a) the separation of the roles of ownership, management, and regulation; (b) unbundling the sector by function; and (c) privatizing generation and distribution functions. The Electricity Act and the Gas Act were enacted in September 1998 to provide the legal basis for the reform effort, which had commenced even earlier. Moldenergo was restructured into 15 Joint Stock companies- three for generation, five for distribution, one for transmission and dispatch, and six others for heat distribution and construction services. The heat distribution network companies were transferred to the municipalities. A National Energy Regulatory Authority

98. In addition, SIIF Moldova (a French consortium including EdF) got a permit to build a gas fired 125 MW gas turbine near the capital city. Its current status is not clear.

99. In the context of restructuring the sector the 35 kV lines would become part of the distribution company infrastructure.

100. The level of cash collection was 30% as late as 1998. Overdue payments from government entities alone amounted to 68.3 million lei by 1998.

(ANRE) was established as an independent and professional body to license the participants and regulate the electricity, heat and gas sectors.

Initially Moldtranselectro (MTE) handled not only transmission and dispatch functions, but also acted as the single buyer in the system, buying from the generators within and outside the country and selling to the distribution companies. This did not solve (but actually aggravated) the non-payment problem and therefore the Government by Decree No. 1000 dated October 2, 2000, ordered that the single buyer model be given up, and transferred the transmission and distribution assets and responsibilities to a newly established Moldelectrica (ME), which acted purely as an independent transmission system operator (TSO) and had no responsibilities to buy and sell electricity. Under the new trading regime, the distribution companies were responsible to buy the electricity needed for their franchise areas directly from domestic generation companies, foreign generators or the import agents licensed by ANRE for this purpose, on the basis of bilateral contracts. They were also under an obligation to absorb the domestic production of electricity. As the domestic production is small in relation to demand, this condition is not perceived as onerous. MTE thus became a shell company with no physical assets and no role in the sector except to carry the historic or stranded debts of the sector.

Privatization

All five distribution companies were offered for privatization to strategic investors through competitive bidding in 1999. Interested strategic investors included Union Finosa of Spain, ABB of Sweden, EdF of France, AES of USA, Cinergy of USA, ESBI of Ireland, RAO UES of Russia, and Luganskoblenergo of Ukraine. The last two failed to qualify and Union Finosa (UF) submitted the best bid for all five distribution companies. Since under the conditions of bidding, no one investor would be allowed to buy all five companies, the sale to UF was limited to three distribution companies (covering the Capital, Central and South regions) accounting for over 70% of the total electricity sales in the country. UF paid for 100% of the shares in these three companies a sum of $25 million and undertook to invest another $60 million in the next five years for rehabilitating the system. UF also assumed all accounts receivables and accounts payables less than 60 days old. All other short term and long term debts were transferred to MTE. UF thus started operating the three utilities from February 2000.

UF had to face initially a great deal of resentment and opposition from the conservative and disgruntled sections of the body politic, and had to deal with many law suits, and harassments at the hands of court of accounts and the police. It was also subject to informal government pressures and criminal intimidations especially during December 2000–May 2001, when the country was trying form a new government. To keep up its election promises, the new government also initially leaned on ANRE to discourage tariff increases. The Mayor of the capital city gave UF a hard time and refused to pay the increased tariffs. Despite all this opposition, UF went about their work systematically, dramatically improved system reliability, ensured 24 hour uninterrupted supply practically to all consumers who paid their bills promptly, bought all its power needs against cash payment and greatly improved the cash flow in the system. Collections improved dramatically to near 100% of the billings and most of it in cash. The government realized the practical advantages of commercialization and independent regulation and by October 2001, ANRE raised the tariff levels based on applications and hearings. The government also started protecting UF from the machinations of the corrupt elements of the society. System losses are still high, but UF is running an efficient anti-theft campaign to bring down the theft losses.[101] Progress in collection from government entities and some large industrial consumers continues to be somewhat difficult. However, the distinct success of UF in improving collections and cash collections had a healthy demonstrational effect on the two

101. Meters are broken and tampered with. Use of locally made equipment, which reverses the direction of rotation of the meter dial to cheat the electricity supplier, is extensive. See BBC report of Jan 2001 for details on how UF is fighting these problems.

remaining state owned distribution companies of the North and North West regions and they have also shown near 100 % collections and near 70% cash collections in 2001.

These two state owned distribution companies handle about 30% of the total electricity sales in the country and have a customer base of 720,000 and 540,000 respectively. They still have high system losses (27% and 38% respectively), and though their current collection efficiency has greatly improved, as noted above, they have large historic debts and old accounts receivables and payables. Their privatization to strategic investors is being handled with the help of HSBC bank as the privatization advisor. The waning investor interest in the emerging markets could make the privatization difficult, in which case alternatives such as a well structured management contract would have to be considered, while seeking investment funds from the debt markets to undertake the urgently needed rehabilitation programs to reduce technical losses in the system.

It is the intention of the government to retain the Moldelectrica and the generating company owning the hydroelectric unit under state ownership and have them regulated by ANRE on the basis of historic costs, projected energy balance and 5% mark up for "profits"(this is the current methodology followed by ANRE for all, in the sector). The two generating companies owning three CHPs are sought to be privatized with the help of Credit Commercial de France as investment advisor. These units are driven by heat demand and would thus be unable to operate optimally as electricity generating units. Their customers, the heat distribution networks, are practically bankrupt on account of low prices and extremely poor collections. This privatization would thus be very difficult and the package needs to be structured properly to elicit some investor response. When the country develops decentralized space heating alternatives, the district heating systems have to be scrapped.

Tariffs

Tariff revisions till about 1999 could not keep pace with steeply rising fuel and imported electricity costs. Numerous and large tariff increases in local currency terms were still inadequate on account of high inflation and steep devaluation of the local currency. And there were extensive internal cross subsidies. Thirty seven categories of people were entitled to privileged tariffs and the system was unrelated to the income levels of these people. Nearly half a million people were covered by such privileged tariffs or tariff discounts, causing serious problems to the energy entities. Compared to the cost of this subsidy (at about 378 million lei), the amount provided in the state budget for compensating the utilities was only 45%, and that amount too, rarely reached the utilities on account of budget pressures. Recently the government is pursuing the policy of abolishing the system of privileged tariffs and protecting the vulnerable section through direct subsidies, without distorting tariffs. The appointment of ANRE greatly facilitated timely and appropriate tariff adjustments, though initially the government tended to lean on ANRE to discourage tariff increases. As of now the average retail tariff for the three regions served by UF is about US cents 5.23/kWh. The retail tariff in the other two regions is US cents 5.0/kWh.[102] The generation tariff is about cents 0.537/kWh for the hydro power, and about cents 2.9/kWh for the CHP units. The transmission tariff is cents 0.264 per kWh. UF buys most of its power from the Transnistria thermal plant at about cents 2.5 per kWh.

Stranded Debts

The three distribution companies were sold to UF after MTE assumed all their debts older than 60 days. This was done to sell the companies with a cleaner balance sheet and to attract greater investor interest. This also protected the systems from the threat of foreign suppliers to cut off supplies for old debts. The historic arrears and debts are now with MTE. As of February 2001, it had an accounts receivable of 838 million lei and an accounts payable of 1,737 million lei. Among the

102. The tariff in local currency is 0.72 and 0.63 per kWh from October 2001. At the current exchange rate of 13.33 lei to a US dollar, this amounts to cents 5.4 and 4.73 respectively. There are also slightly lower prices for homes with electric cooking stoves.

receivables, only a sum of 56 million lei is considered recoverable. In addition, the distribution companies in the north and north-west region still carry their historic debts and they may also have to be assumed by MTE in the context of their privatization. Solutions to this stranded debt have to be found yet. They may include assumption of a part of this debt directly by the government as public debt and recovering the balance from the consumers by way of a surcharge on tariffs over a convenient period. If all debts were to be recovered over a 10 year period at an interest rate of 7% per year, the tariff surcharge may amount to about 8% of the current retail tariffs.

Conclusions

Given the small size of the country and its very small power system, Moldova would not normally be considered a suitable candidate for sector reform involving sector unbundling and competition and high transaction costs. Privatizing the vertically integrated utility as a whole would probably appear as a more appropriate solution. However the utility was saddled with the insurmountable problems associated with heat supply, and its privatization (with the CHPs still embedded in it) would have been almost impossible. Some amount of unbundling was thus inevitable. Further, the country depends on imported power for more than 75% of its needs and its system is closely interconnected to those of Transnistria, Ukraine, Romania and Bulgaria. In the past when the government owned the sector entities, the payment debts incurred by them devolved on the government and had a serious macroeconomic impact. The privatization of the distribution entities and allowing them to procure electricity directly from domestic and foreign sources enables the government to distance itself from the obligations of the distribution companies. The financial strength and solvency of the new investors and their affiliates enables imports at more reasonable prices[103] and on an uninterrupted basis. Once the domestic CHPs are retired or privatized and once the remaining two distribution companies are also privatized, the distancing of the government from the future sector debts would be complete. Under these circumstances, the type of sector reform attempted in Moldova could be regarded as acceptable. Further the related trading arrangements became possible because (a) the dispatch is both technically and managerially simple; (b) there are effectively only three CHPs to dispatch and they follow heat demand; (c) there are no transmission congestions and bottlenecks; and (d) selective supplies to distribution companies is possible.

However the need for fragmenting the distribution into five small entities is not clear. It is interesting to note that UF made a bid for all five and got three because of the condition that the same investor should not own all five. UF having at least three of them with 70% of sales, gives them some economy of scale. One may hope that the remaining two would be sold to one investor.

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103. Energy import prices are believed to have dropped by about 25% to 30% on account of solvent buyers.

POLAND

Introduction

The size of the electricity system of Poland, its interconnections to the systems of Western Europe, Eastern Europe and the Former Soviet Union (FSU) countries, its active import-export trade in electricity, and its commitment to European Union (EU) accession make it, prima facie, a candidate for sector reform involving unbundling of the functions, provision of non-discriminatory access to transmission and distribution services (hereafter referred to as third party access or TPA), introduction of competition and consumer choice.

With a population of 38.6 million and a GDP of $157.7 billion[104] in 2000, Poland has the largest electricity system among the East European countries. Poland is already a member of the OECD (since 1996) and NATO (since 1999) and is one of the ten countries expected to achieve accession to EU by 2004.

System Dimensions and Characteristics

The total installed electricity generation capacity in Poland in 2000 was 34,587 MW including 2,641 MW of captive generating units belonging to large industries (hereafter referred to as auto-producers) who sell their excess energy to the utility grid. The remaining total of 31,946 MW of utility plants consisted of:

- 15,405 MW (or 48.2%) of hard coal fired steam turbine generator units for producing electricity;
- 9,178 MW (or 28.7%) of brown coal/lignite fired steam turbine generator units for the production of electricity;
- 5,196 MW (16.3%) of combined heat and power plants (CHP) mostly fired by hard coal and some by natural gas; and

104. The size of its GDP is the largest among those of the 12 countries seeking accession to EU and would be the seventh largest were it now a member of the EU.

- 2,167 MW (6.8%) of hydroelectric units including 1330 MW of Pumped Storage units and 115 very small hydroelectric units mostly owned by the distribution companies.

The system peak demand in 2000 amounted to 22,289 MW and though the gross reserve margin at about 31% would appear to be adequate, the system has a surplus of base load capacity and a shortage of peaking capacity and relies on imports and exports to meet its peak demand and keep the base load units going.

Poland uses all the brown coal it produces in its mine mouth power plants. It has a hard coal production capacity which adequately meets the full needs of its electricity sector and leaves a substantial surplus of good high quality coal (over 37 million tons in 1998) for exports. The country relies on imports for over 95% of its oil needs and over 60% of its natural gas needs (1998).

Polish electricity transmission system in 2000 consisted of:

- an extensive network of 110 kV lines (32,322 kms);
- an overlay of 220kV lines (8,116 kms) to which most of the large generating units are connected;
- a grid backbone system of 400 kV lines (4,660 kms) which enables bulk transfer of electricity within the country and wheeling of power across the country; and
- one 750 kV line (114 kms) mainly to facilitate power imports from Ukraine.

The medium voltage (1 kV to 60 kV) network had a total length of 278,319 kms, and the low voltage lines below 1 kV totaled 389,871 kms. The total transformer capacity of the network amounted to 118,772 MVA.

The Polish transmission system is well interconnected to those of its adjoining countries, and became successively a member of POKOJ system (covering the previous systems of Ukraine and East European countries), CENTRAL system (covering the new systems of Ukraine, Poland, Hungary, Czech, and Slovakia) and is now well integrated into the West European Union for Coordination of Production and Transmission of Electricity (UCPTE). It has also strong transmission links to Ukraine and Belarus.

In 2000, Poland imported 3,290 GWh of electricity mostly from Germany (61%), Ukraine (19%) and Belarus (5%), and exported 9,663 GWh of electricity mostly to Czech Republic (92%) and Germany (7%). Domestic generation amounted to 145,169 GWh, of which about 5% related to autoproducers. Total gross energy supply from the utility plants, imports and purchases from autoproducers, cogeneration plants and others amounted to 141,629 GWh. This was accounted for: (a) exports of 9663 GWH (6.8%), (b) domestic sales of 102,307 GWh (72.2%), and (c) total system losses of 29,659 GWh (21%). The total system loss consisted of (a) auxiliary consumption by thermal and hydro generating units (8.8%), (b) energy used in the pumped storage units (2.1%) and (c) transmission and distribution and non-technical losses (10.1%).

The consumer mix and consumption mix in 2000 were as shown in Table 1 below:

Total sales in 2000 were only very slightly higher than those in 1990 which were 102,259 GWh. During the decade the share of the households had remained practically unchanged at around 20.5%. The share of the agricultural consumers went down significantly, while the share of HV consumers also went down. The lost share went mostly to other LV consumers and partly to MV consumers.

Structural Changes

Before 1987, the sector consisted of five regional State Owned Enterprises (SOEs), which were all vertically integrated utilities. During 1987–1990, the electricity and lignite (brown coal) sectors were consolidated and the Electricity and Brown Coal Board (WEWB) was created as a state owned conglomerate with 108 businesses including 28 generation enterprises, 33 distribution enterprises, one transmission and load dispatch enterprise, four brown coal mines and several

TABLE 1: ELECTRICITY CONSUMER MIX AND CONSUMPTION MIX IN POLAND

Categories of Consumers	No. of consumers ('000) in 2000	% share in 2000	Consumption GWh in 2000	% share 2000	% share 1990
High Voltage (= or >100kV)	0.3	—	27,137	26.5	30.8
Medium Voltage (1kV to 60kV	26[105]	0.2	25,305	24.7	21.4
Railways, Trams- Trolley buses	—		4,329	4.2	5.2
Low Voltage Total <1kV	15,263	99.8	45,537	44.5	42.8
Total	15,289	100.0	102,307	100.0	100.0
Low voltage breakdown:					
Households	11,123	72,6	21,034	20.6	20.4
Agriculture	2,195	14.4	4,773	4,7	7.9
Streetlights	—		1,825	1.8	1.3
others	1,945[106]	12.8	17,905	17.5	13.2

other related manufacturing, construction, maintenance, and research enterprises. WEWB functioned as a state monopoly under the supervision of the Ministry of Industry and Trade (MIT). As a result of the recommendations of an ESMAP study, WEWB was dissolved in September 1990 and all the non-core enterprises were spun off. The Polish Power Grid Company (PSE) was set up at about the same time as a 100% state owned Joint Stock company (JSC) to own and operate the national transmission grid and the national and four regional load dispatch centers. The generation and distribution enterprises became "autonomous" and reported directly to MIT. On the basis of continued economic and sector work assistance provided by the Bank, the government articulated the main elements of sector reform in the Development Policy Letter issued in connection with the Bank's energy SECAL loan of $75 million (loan # 3377-POL approved in June 1991).[107] The key elements were: (a) pricing reform; (b) de-monopolization and restructuring of the sector; (c) commercialization and privatization; and (d) establishment of a regulatory regime.

Though the government allowed the second tranche ($37.5 million) of the above SECAL to lapse in 1994, because of its difficulties in presenting to the Parliament the new Energy Law needed (among other things) to establish the regulatory body, it made good progress in correcting the distortions in the structure of electricity and heat tariffs and in converting many of the electricity enterprises into JSCs. A law passed in February 1993 enabled such a transformation and the transfer of transmission assets from the distribution enterprises to PSE. It also enabled MIT to carry out "commercialization" of the electricity and coal sectors. The sector unbundling effectively commenced at this stage. District heat distribution enterprises were transferred to local governments. All 19 CHP plants were registered as individual JSCs. Similarly all 33 distribution enterprises[108] were registered as JSCs. Among the electricity generating enterprises, four were converted into JSCs and the rest were retained in the form of 12 autonomous generation SOEs, for eventual corporatization. PSE, already registered as a JSC in 1990, was able to get possession and formal transfer of all transmission

105. Includes the next category also.
106. Includes street lights.
107. Under the earlier Structural Adjustment Loan # 3247-POL approved in July 1990, the government liberalized coal prices and undertook to regulate relative prices of oil, gas, electricity, and heat to ensure that they are not out of line with those in the foreign markets.
108. Six of the distribution companies had about 150,000 customers each. The rest had over 200,000 customers each.

assets. PSE also became the substantial owner of all pumped storage units[109] (1,330 MW) with about 87% of the shares in the Pumped Storage Power Plant Company. PSE became the key player in the sector with major responsibilities including: (a) owning and operating the transmission grid and all the load dispatch centers; (b) generation and transmission planning; and (c) imports and exports of electricity and wheeling of power across the country.

The most significant development was the emergence of PSE as the single buyer of electricity in the wholesale market. PSE had the responsibility to determine the capacity and energy charges payable to the various generating units, taking into account, among other things the need for them to undertake rehabilitation and especially retrofits for compliance with environmental norms and conclude long term (20 years or more) Power Purchase Agreements (PPAs) with all the generators connected to the 220kV and 400 kV grids.[110] Small generating units feeding directly into 110kV network and auto producers could have a PPA directly with the Distribution companies or with PSE if they so desired. PSE purchased about 80% of the output of the large generators connected to the 220 and 400 kV grids on the basis of long term PPAs and about 15% to 20% of their output on the basis of short term PPAs (one year or less). The short term and daily contracts (mainly to balance the system) allowed for higher profit margins to compensate for the higher dispatch risk and therefore were costlier than the long term contracts. Spot or exchange market was envisaged for 5% of the output only at a later stage after gaining experience in the wholesale market. The system was dispatched in the merit order of the contract prices. The cost of the electricity thus purchased and dispatched by PSE from many generating units was pooled and the average price was used to sell electricity to the distribution companies at prices determined for each distribution company on the basis of transfer price guidelines issued by MIT. These prices indicated separately the transmission charge, thus effectively separating the generation and transmission tariffs, paving the way for TPA at a later stage. The final tariffs for end-users of the distribution companies were determined by the Ministry of Finance based on the recommendations of PSE and MTI. During this period substantial progress was made to correct the structural distortions in tariffs for electricity by raising the household and agricultural tariffs to a level higher than those of HV and MV consumers (see Table 2 below).

Thus in 2000 the overall average tariff/kWh amounted to US cents 4.5 and the average tariff for households amounted to US cents 5.2

The above single buyer model was largely on the lines recommended by the consultants of the Bank and those of USAID and the Bank at that time thought well of it as precursor to competition and private investment. However towards the end of 2000, the Bank came to the belief that the

Table 2: Electricity Tariff Changes in Poland (zl/MWh)

Consumer	1990	1995	1999	2000
Overall average tariff	19	119	182	199
HV consumers average tariff	20	86	131	144
MV consumers average tariff	27	109	163	177
LV consumers average tariff	18	150	226	247
Households	10	140	209	232
Agriculture	12	143	215	239
Memo Item: Exchange rate 1US$= zl				4.4295

109. These units are used to meet the peak demand in the system, and this was the logic behind PSE control of this asset for system regulation. However the Pumped Storage Power Plant Company set up in 1993 owns a total of 23 hydro units with a total capacity of about 1500 MW. PSPP owns about 85% of the pumped storage plants and 74% of the total hydro electric plants in the country.

110. These were based on the transfer price guidelines issued by MIT.

single buyer model and especially the guaranteed PPAs may have actually been an impediment to furthering competition here and elsewhere.[111]

Move Toward Competition

Despite the lapsing of the second tranche of the SECAL loan, Bank's advisory assistance through non-lending services continued and as a result the Government was able to approve two key policy documents entitled " Energy Policy Guidelines Until 2010" (October 1995) and "Demonopolization and Privatization of the Electricity Sector" (September 1995) which laid out their plans for the electricity sector. The Government also managed to have the new Energy Law (enabling the envisaged reform) passed by the parliament in April 1997. The law came into effect towards the end of 1997. Early in 1998 the government also committed itself to adapt its electricity market regulations to EU standards within four years.

The new Energy Law sought: (a) provision of energy security; (b) efficient and rational use of fuels and energy; (c) development of competition in the energy sector; (d) counteracting the negative consequences of the operation of monopolies; (e) protection of environment; and (f) protection of consumer interests, choice and costs. At the government level it enabled the separation of policy, regulatory, and ownership functions by making the Ministry of Economy (former MIT) responsible for policy, Ministry of State Treasury responsible for ownership functions and by creating a new Energy Regulatory Authority (URE) to be responsible for regulation and promotion of competition in the energy sector. The Chairman of URE is appointed by and reports to the Prime Minister and is assisted by an advisory board of seven members representing various special interests appointed by the PM on the recommendations of the Ministry of Economy. The Chairman would have a fixed tenure and cannot be removed from office except on the basis of malfeasance.

The reform process under the new law (and the documents referred to above) envisages effectively moving away from the single buyer model (after the necessary brief interim period) towards a competitive market. The key elements of the process are: (a) introduction of competition in the wholesale electricity business, through the use of a contract market and an exchange (spot) market; (b) privatization of the generating companies, CHP companies, distribution companies and eventually PSE also; (c) further unbundling of the supply function from the distribution wires function and licensing electricity traders; (d) eventually providing freedom to choose the supplier to all consumers; (e) guaranteeing free and nondiscriminatory TPA to all domestic producers in respect of the transmission and distribution wires network; and (f) freeing the commodity price of electricity and heat from regulation and regulating only the transmission and distribution wires services.

The reform is being implemented slowly and substantially behind the time schedule originally envisaged and with frequent political back tracking inevitable in a multi party democracy. The authority was transferred to URE by the Ministry of Finance to regulate end tariffs for electricity (1999) and heat (2000). URE has meanwhile licensed all key players in the electricity sector. In June 2000, executive ordinances were issued clarifying the right of the energy suppliers to enter the consumers' premises to carry out meter readings and to inspect the installations to detect any illegal consumption as well as to disconnect supplies to non-paying customers. They also clarified the responsibilities of the apartment block owners vis-‡-vis the utility companies and the owners or tenants of individual apartments. They also gave the government the power to require the distribution companies to buy a portion of their electricity or heat from renewable and non-conventional sources, somewhat like the portfolio standards followed in USA. The phasing in of TPA and consumer choice commenced in 1998, and, as of January 1, 2000 all consumers with an annual consumption of 40 GWh or more have the freedom to choose their suppliers (see Table 3 below). There is an estimate that in 2000 about 30% of the total sales was covered by sort of consumer choice.

In December 1999, Gielda Energii SA was established to set up an energy exchange in Poland. It is a consortium of several energy companies including Endesa of Spain. The Polish treasury

111. See Viewpoint Note # 225 of December 2000.

TABLE 3: PROGRAM OF PHASING IN TPA AND CONSUMER CHOICE IN POLAND

Date	Minimum Annual Consumption level (GWh)	No. of consumers	Share in Total Sales(%)
1998	500	21	21
1.1.1999	100	83	36
1.1.2000	40	179	43
1.1.2002	10	610	51
1.1.2004	1	3296	59
1.1.2005	All	All	100

holds 30% of the shares in this company. It commenced operation January 1, 2000 and the participants were 36 power generating companies, 33 distribution companies, PSE and 183 large industries. The ultimate goal is to cover at least 30% of total sales in the market by the spot market or exchange routed transactions. As of now only 1% of the total sales is believed to be thus traded. Present preponderance of long term contracts has to be brought down. The strategy of phasing out the long term guaranteed PPAs, first by transferring them to the distribution companies and later resorting to buy-out options (such share swaps or compensation), is yet to be fully evolved. Till then the long term PPAs would prove to be a major constraint to effective competition.

Private Sector Participation

Private sector participation has taken different forms. They include:

- Partnership arrangements between PSE and Commonwealth Edison of USA going on since 1991 focusing on providing advice on financial soundness, customer relations, human resource management plan, pricing, demand side management, and system operation and maintenance is the earliest example of private sector participation.
- Joint ventures between public sector and private sector such as: (i) Polengia SA, a joint venture among PSE, a German distributor and a Polish firm for selling privatized electricity from Poland and electricity from Russia to West European markets; and (ii) Gielda Energii SA, a joint venture among the State Treasury, Endesa of Spain and other energy firms for the operation of the power exchange.
- Independent Power Producers constructing new capacity under the PPA arrangements with PSE such as: (i) lignite fired 800 MW Belchatov Unit 2 with 49% shareholding by a consortium of Polish companies and 51% by the Belchatow Power Plant company and with debt financing by Polish banks; (ii) 116 MW gas fired CHP at Nowa Sarzyna in which Enron holds 97.5% of shares and a local consulting firm holds 2.5% with a capital cost of $132 million; (iii) 1000 MW gas fired combined cycle power project at the old nuclear power plant site near Lake Zarnowiec being constructed by US consortium ZEG; and (iv) a new CHP plant (to replace a 100 year old plant) at Chorzow by PSEG Global of USA.

Privatization of the electricity entities owned by the government is however the central and key component of the sector reform strategy. The main aims of such privatization are: (i) promoting competition, (ii) introducing modern commercial managerial competence, (iii) securing the external resources needed to modernize, rehabilitate and make environmentally sound the existing electricity infrastructure and to add new capacity needed to meet future demand; and (iv) to secure the best value for assets privatized. The entities to be privatized were: (i) 12 SOEs and 4 JSCs owning large power generating units; (ii) 19 JSCs owning CHPs; (iii) 33 JSCs engaged in electricity distribution; and eventually (iv) PSE.

Energy is regarded as a strategic sector in respect of which government must still have a significant stake. In the initial cases of privatization EDF got 55% in Krakow CHP, Vattenfall got 55% in Warsaw CHP. Since then the government is trying to restrict foreign shareholding in new privatizations to 45% in existing CHPs, 35% in existing large electricity generating units, and to 25% in distribution. However, it would appear that subsequent to the initial privatization, the foreign investor could raise his share holding by undertaking new investments for rehabilitation, modernization and expansion. Further, the government is currently negotiating the sale of 85% of the shares in Stoen, the distribution company in Warsaw, with RWE of Germany.

The methods used include: (a) direct negotiation with the interested party for the price of 20 to 30% of the shares; (b) listing the company in Polish Stock Exchange and making IPOs; (c) selecting the strategic investor on the basis of international tendering. The first three privatizations took three different routes.

- Krakow CHP was directly negotiated with EDF. 55% of the shares were sold for $80 million in 1997 and EDF was expected to invest an additional $25 million over the next 5 years.
- Bedzin CHP was privatized by listing in Warsaw Stock Exchange in November 1998.
- PAK group of generating units (2700 MW) was subjected to international tender in October 1997. National Power of UK was selected for negotiation to sell 20% of shares, but the negotiations failed in 1998 and a consortium led by the Polish company Elektrim was invited and 38.5% shares were sold to them for $88 million in March 1999.

By and large, the preferred method now is to engage a privatization advisor, carry out the analysis, issue international tenders among qualified strategic investors, evaluate the bids and negotiate with the selected bidder and conclude the shares sale.

Completed Privatization

The government had a program of privatizing all 19 CHPs, 17 power plants, and all 33 distribution companies by the end of 2002 and also commence the privatization of PSE in 2002. As at the end of the first quarter of 2002, the government had sold: (i) 25 to 38% of shares in four electricity generation companies with a total generation capacity of 6770 MW (20% of the total capacity in the grid); (ii) 45 to 64% of the shares in seven CHP companies with a total capacity of 2373 MW (electricity) and 11,288 MW (heat); and (iii) 25% of shares in one distribution company for a value of Euro 167.5 million. With promised further investments the investor may own in future 75% of the shares for a total price of Euro 800 million (see Table 4 below for further details).

Outlook for the Future of Further Privatization

The privatization of the remaining CHPs and some of the electricity generating companies are under process. Privatization of generating units and distribution companies are however stalled on account of the debate whether they should be consolidated into larger entities before sale or whether they should be sold as they are. The slowing down of the pace of privatization in Poland is also attributable to several other factors. The labor unions in Poland and especially those of the hard coal and lignite industry are powerful and their interests and sector reform thrusts are not necessarily congruent. Most often the demands of the unions regarding the components of the social package (which the foreign investor has to accept and abide by as a part of the share sale transaction) keep on expanding and the unions do not speak with one voice. Some of the political parties have strong nationalistic fervor and are not overly fond of selling the strategic electricity sector to foreign investors.[112] They wish to consolidate the sector into very large generating entities

112. However, the government plans to list the stocks of these companies in the stock exchange. After EU accession in 2004, people of any nationality could buy the shares through the stock exchange.

Table 4: Electricity Privatizations in Poland

Company/Function	Investor	% of Shares sold	Price Paid million	Capacity MW	Date of sale/ Remarks
Krakow CHP	EdF	63.8	US$80	446(e) 1457(h)	May 1998
Warsaw CHP	Vattenvall	55.0	US$235	984(e) 5625(h)	Jan 2000
Kogeneracja CHP	EdF/EnBW	48.2	n.a.	360(e) 1415(h)	May 2000
Wybrzeze CHP	-do-	45.0	EUR 62	340(e) 1500(h)	Jun 2000
Bedzin CHP	MEAG	52.5	PLN 34	65(e) 496(h)	Jul 2000
Bialystok CHP	SNET	45.0	EUR 49	155(e) 557(h)	Feb 2001
Zielona Gora CHP	Kogeneracja/ Dalkia Termica/PEP	45.0	US$11	23(e) 238(h)	Oct 2001
Tychy CHP	SNET	45.0	PLN 20	40(e) 500(h)	The matter is delayed.
PAK Power	Elektrim	38.5	US$88	2700(e)	Mar 1999
Rybnik Power	EdF/EnBW	35.0	US$120	1800(e)	Mar 2001
Polaniec Power	Tractabel	25.0	EUR 88	1695(e)	Apr 2000
Skawina	PSEG Global	35.0	US$25	590 (e)	Jan 2002
GZE distribution	Vattenvall	25.0	EUR 167.5	—	
G8 Distribution	Iberdrola	25.0	—	—	Under negotiation

capable of competing in Europe and keep them essentially Polish owned. They cite the examples of EdF and four or five mega utilities in Europe virtually unchecked by EU's relaxed attitudes towards energy mergers and wish to follow them. Based on these thoughts some amount of vertical integration of the sector is taking place. PKE is the first such mega energy conglomerate already established by merging six electricity generating companies, one CHP company, three coal mines supplying fuels for them and four distribution companies called Southern Group K4. It will have a total electricity generating capacity of 4,795 MW and heat capacity of 693 MW and the four distribution companies would account for 14% of the total energy sales in Poland. Three other such consolidations are under active consideration (see Table 5 below).

Vertical integration of this kind and the horizontal integration of so much generating capacity will hinder effective competition within the Polish market. The process of further privatization would become more difficult and much slower, if it proceeds at all. Other factors (referred to as back tracking earlier) hampering privatization efforts include; (a) increasing erosion of independence of the regulatory body; (b) introduction of interim price caps or ceilings for price increases by the government;[113] (c) the bias against foreign majority ownerships; (d) inability to solve the problem arising from long terms PPAs signed by PSE and to usher in quickly an exchange market with substantial volumes of competitive transactions; (e) the inability to enunciate clear exchange

113. In 1999, the Ministry of Economy limited price increases in electricity to 15% and in heat to 14% on "macro economic considerations" and to avoid price volatility.

TABLE 5: PROPOSALS FOR VERTICAL INTEGRATION IN POLISH ELECTRICITY SECTOR

Group Name	Generation units	Lignite or Coal mines	Distribution companies
PKE	Jaworzno III, Laziska, Lagisza, Siersza, Halemba, Blachownia, Katowice	Sobieski, Boleslaw, Simiay, Wesola, Ziemowit	Bielsko-Biala, Bedzin, Krakow, Tamow
PZGE	Turow, Opole	Turow, Budryk	Legnica, Opole, Walbrzych, Jelenia Gora
Kozienice	Kozienice	—	Lublin, Rzeszow, Zamosc, Zeork,Lodz-Teren, Energetyka
Belchatow	Belchatow	Belchatow	Poznanska,Gorzow, Szczecin, Lodz, Bydgoszcz

market rules and mechanisms and the prolonged continuation of the single buyer model with its anticompetitive transfer price components.

The Bank made available to the Government advice by an Experts Panel consisting of the former Electricity Regulator of UK, an Electricity Market expert, a Utility Restructuring Expert, an Investment Banker, a Regulatory Lawyer, and a Utility Privatization Specialist. This panel advised the Government in respect of generation : (a) to privatize large generating units individually and small generating units in small groups; (b) to integrate the two lignite fired units with the lignite fields and sell them together; (c) to sell 20 to 45% of the shares to the strategic investors via trades sales and follow it up with floating the stocks in the Polish Stock Exchange; (d) to phase such sales over a two year period; and (e) to prohibit any one investor from having more than 15% of the generation market. In respect of distribution the panel advised against consolidation and suggested that the investors could be invited to bid for groups of contiguous distribution companies. It further advised (a) to privatize distribution companies as entities responsible both for the wires function and for the supply function, but to require them to administratively separate the two functions within the company within a certain period; (b) to sell each company or each group of companies in two tranches by selling 20 to 25% of the shares in the first tranche preferentially to industry investors and selling the rest of the shares through public floatation in the second tranche; (c) to sell each company in two rounds, focusing in the first round on the quality of the bid and bidder and in the second round, on price; and (d) to limit the ownership of any investor to less than 12 to 15% of the market. The Panel also stressed the need for the state to maintain influence over strategic decisions on transmission and distribution.

Recent pronouncements by the Minister of State Treasury seem to indicate that the government is in agreement with this line of thinking. He is believed to favor the floatation of shares of the PKE, (which will be a large domestic electricity company capable of providing good competition) and trade sales of shares to foreign strategic investors in respect of four other generation companies, namely Ostroleka, Staloa Wola, Kozienice, and Dolna Odra.[114] Unlike in the past, he is believed, now, to favor sales to foreign investors initially giving them minority stakes, and allowing them to secure majority control quickly. In this context it is also believed that the privatization of all other remaining entities except PSE would now be completed by the end of 2004.

Lessons from the Polish Experience

Though the Polish government moved more slowly than some other Eastern European governments, its focus to get things right would appear to have been appropriate. The unbundling of the

114. Total installed capacity of all 4 companies would be of the order of 5,500 MW.

WEWB monopoly into generation, transmission and distribution entities was timely. The adoption of the single buyer model with PSE as the central player and operating on the basis of guaranteed long term PPAs was able to attract some foreign investors as IPPs, but soon proved to be somewhat of an impediment to adopt exchange/spot market based on bids and offers and thus move into a competitive situation. The focus on correcting structural distortions in tariff, removal of subsidy burdens from the utilities, establishing a separate and professional regulatory body with reasonable autonomy, adoption of methods (of contracting for power) to encourage generation companies to undertake the urgently needed rehabilitation to improve efficiency and reduce pollution, the enunciation of clear policy in 1995 regarding the direction of reform moving away from the single buyer model, the enactment in 1997 of the new Energy Law to enable it, and the issuance of executive orders outlining the property rights of energy suppliers in being able to enforce payment of bills through disconnection of non-payers were all the right steps to set the house in order, and attract foreign investors. These preparatory steps and the cautious and incremental approach to privatization seem to have enabled the government to get reasonable values for the shares sold. The interest of foreign investors (at least from those in Western Europe) in the Polish electricity sector appears to be still significant.

However, there are a number of problems yet to be addressed. They include:

- Under the new Energy Law of 1997 of Poland, TPA is available only to the domestic producers and not to foreign suppliers and this would need to be addressed in the context of EU accession.
- The problem of the existing long term PPAs of PSE need to be addressed.
- The autonomy and independence of URE needs to be respected in letter and spirit to retain investor confidence.
- There should be a clearly enunciated policy on the minimum shares to be held by the State treasury and the purposes for which they will be used.
- The possibility of selling all the shares and retaining only a golden share to be used only for reasons of the security of the state should be explored.
- In view of the overriding importance attached by the body politic to early EU accession, a consensus among the political parties should be built regarding the settled direction and pace of reform to avoid the present stop-go-stop approach.
- Attention should be devoted to the reform of accounts and disclosure requirements and for improving the content of the cost of service regulation by URE especially in the areas of inflation accounting, revaluation of assets and debts, and uniform definitions to enable derivation of tariffs which makes sense to the prospective investors.

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TAJIKISTAN

Introduction

The case of Tajikistan is remarkably similar to that of Kyrgyz Republic. Tajikistan, Uzbekistan, and Kyrgyz Republic are both geographically and electrically intertwined and continuously trade in electricity and fuels. Seriously affected by a prolonged civil war between a secular government and the Islamic conservative opposition during 1991–1997, the GDP of Tajikistan contracted by more than 60%. With a population of 6.4 million (more than 60% of which lives below the poverty line) and a per capita GNP of about $170, Tajikistan is the poorest among the former Soviet Union countries. Its external debt designated mostly in US dollars is about 118% of its GDP. The local currency[115] equivalence to one US dollar declined in value from 135 Tajik Rubles at the end of 1995 to 2230 Tajik Rubles at the end of 2000.

Its oil reserves (12 million barrels) and natural gas reserves (200 BCF) are far too small to meet the domestic demand of 29,000 barrels of oil/day and 41.3 BCF of natural gas per year, resulting in the country's substantial import dependence for these fuels. Its declining coal production (20,700 tons in 2000) meets fully the country's declining coal demand and leaves 50% of the production for export. Its hydroelectric potential estimated at 40,000 MW with an annual energy content of 527 TWh is even greater than that of Kyrgyz Republic. However, only about 10% of this had been developed.

System Dimensions and Characteristics

The installed electricity generation capacity is about 4,400 MW consisting of seven large hydroelectric stations[116] with a total of 4,052 MW and two fossil fuel fired thermal plants at Dushanbe and Yavan with total capacity of about 350 MW. The construction of Rogunsk Hydroelectric plant

115. The local currency since May 1995 was Tajik ruble, which was replaced by a new local currency Soumoni in October 2000, when Soumoni was equal to 1000 Tajik rubles.

116. Of these, the largest is Nureksk Station with 9 x 300 MW. The others are Golovnaya (210 MW), Baipazan (600MW), Namadgud, Lenin, Pamir 1, and Qayroqqum (126 MW) Stations.

TABLE 1: TAJIKISTAN'S EXPORTS AND IMPORTS OF ELECTRICITY (GWH)

Item	1990	1995	1999	2000
Generation	18,200	14,800	15,797	14,247
Exports	5,700	4,200	3,831	3,901
Imports	6,900	4,900	3,641	5,242
Available for domestic market	19,400	15,500	15,607	15,580
Net Country status	Importer	Exporter	Exporter	Importer

(3,600 MW) estimated to cost $2.0 billion was commenced during the Soviet rule and still remains to be completed.[117] The area has both security and seismic problems hampering progress apart from the lack of funds. When completed, it would be the 15th largest hydroelectric generation station in the world. Similarly, Sangtuda Hydroelectric station (670 MW) was also commenced during the Soviet days and, after an initial expenditure of $100 million, had been languishing for want of funds. Another $350 million is believed to be needed to complete the project. The government has set it up as a joint stock company in which private sector would be allowed majority shareholding. Iranian and Russian financiers are believed to have expressed interest. The government is also desirous of resuming the construction of 15 smaller-sized hydroelectric projects. Russia's equipment manufacturer Energomash is reported to have commenced deliveries of equipment for five of these projects, viz., Andarbak (250 MW), Shkev (74 MW), Yemts (100 MW) Langar (60 MW), and Yamchun (150 MW). Several other large hydro projects, such as Dashtijum (4000 MW), Shurob (750 MW), Kaphtarguzar (650 MW) are under the planning stage, though it is not clear how the needed funds would be raised. Its transmission system consists of 226 km of 500 kV lines, 1,203 km of 220 kV lines, 2,839 km of 110 kV lines. Distribution is by 35 kV, 10 kV, 6 kV, and 0.4 kV lines. Electrification of the country is nearly complete and almost every household has access to the electricity grid.

The power system consists of two grids - North and South - that are not directly interconnected because of the high mountain range which divides them. In the Southern grid, the eastern portion called Gorno Badkshan is connected to the western portion by a 35 kV line with very limited power transfer capacity. Thus for all operational purposes the country may be regarded as having three separate grids not interconnected to each other. Though they are not interconnected within the country, the northern and southwestern grids are interconnected with the power systems of Uzbekistan and Kyrgyz Republic. The northern grid, which gets about 30% of its needs from the Qayroqqum HE station, imports the rest of its needs from Uzbekistan. There is a continuous interchange of electricity among the three countries. Tajikistan also exports electricity to the southern areas of Kazakhstan, mainly in summer. The volume of exports and imports vary as a function of water availability (see Table 1).

In winter the hydroelectric generation is greatly reduced and dependence on imported fuels for electricity increases. Inability to pay the bills of foreign suppliers results in shortages of fuel and in significant load shedding. The quality of supply also suffers from overloaded lines and transformers leading to frequent forced outages. Scheduled power outages of supplies to rural and urban consumers on a rotating basis are normal during winter.

Electricity sold to consumers within the country declined from 16,518 GWh in 1990 to 11,039 GWh in 1997 but rose to 13,300 GWh by 1999. During 1990–1998, the share of industrial consumption declined from 71% to 43% while the share of residential consumers went up from 9% to 38%. The share of the agricultural consumers remained without much change at around 20%. Reflecting this change in the pattern of consumption, the peak demand declined at a slower rate from 3,793 MW to 2,925 MW. The overall system loss is believed to be in the range of 15%,

117. $800 million is believed to have been spent and the government is looking to the private and external sources for the balance of the funds, and especially for at least $120 million to finish the first phase.

most of it being technical due to the overloading of the lines and transformers. The system loss level may have been understated, since there is extensive un-metered flat rate supply to a large number of households.

Collection efficiency is very low and the use of offsets and barter is extensive. BT has thus accumulated a large level of accounts receivable. One of the main reasons for this is payment defaults and delays by TadAZ[118], the world's largest Aluminum smelter located in Tajikistan. It consumes about 34% of the country's total electricity sales. TadAZ imposes a heavy burden on the economy, first by forcing the country's utility to import about 835 GWh of electricity at prices substantially higher than the price of local electricity to ensure uninterrupted supply, and second by not paying its bills and accumulating arrears to the utility, creating a serious national problem. Accounts receivable of BT which stood at a level equaling 13 months' sales in 1998 were sought to be reduced to 6 months by 1999 and 3 months by 2000 under the Asian Development Bank (ADB) covenants. However, the A/R was in the range of 11 to 12 months' sales during 1999 and 2000 and the ADB has postponed the target dates to 2001 and 2002 respectively. The A/R at the end of 2001 seems to have come down only to the level of about 9 months' sales. The debts of TadAZ to BT amounting to $18.3 million have been restructured in February 2000 and TadAZ is reported to be current on rescheduled payments. Current collections are about 50% of the current billings and only about 50% of the collections are in cash, despite the issue of a decree in August 2000 prohibiting the use of barter trades.

Consultants to ADB have conservatively estimated the LRMC of supply at US cents 1.26 per kWh for supply at 500 kV to TadAZ, US cents 1.5 per kWh for supply to other industries at 35 kV to 220 kV, and US cents 1.65 per kWh for low voltage supplies. There are other estimates which indicate that LRMC could be higher at about US cents 2.3 per kWh. Average tariff per kWh had been much less than US cent 1.0 for quite some time and does not clearly cover the cost of supply. While the level of tariff is low, the structure is skewed as the residential consumers and agricultural consumers are heavily cross-subsidized by industrial consumers. Under the adjustment lending program of ADB and the IMF assistance program, the government has covenanted to improve the cost recovery in respect of residential consumers to 50% by December 2002 and to 100% by December 2004. Cost recovery in respect of industrial consumers is covenanted to reach 100% by December 2001. Tariff increases are to be driven by the objective of securing a rate of return of 6% on average net fixed assets in operation. Despite several tariff increases ordered by the government raising the tariffs in local currency terms, the tariff level expressed in US cents continues to remain low on account of the steep devaluation of the local currency. Category wise tariff changes during the years 1997–2000 are summarized below.

Current average tariff of US cent 0.7/kWh does not cover fully the operational cost. Industrial tariff at around US cent 1.03 subsidizes residential tariff at around US cent 0.4. The government has covenanted to the Asian Development Bank and to the IMF that the average tariff /kWh for industrial consumers would be adjusted to US cent 1.03 by January 2002 and that for residential consumers would be raised to US cent 0.75 by January 2003 and to US cent 1.5 by January 2005. The tariff structure includes a quarterly automatic tariff adjustment mechanism for factors beyond the control of the utility and also a lifeline rate for residential consumers for consumption below 150 kWh per month. The lifeline rate would be maintained, but not allowed to rise in real terms. It will probably take a few more years to achieve a tariff level adequate to cover full cost of supply and provide a reasonable return on investments.

Structure of the Sector and Plans for Reform

Barki Tajik is the vertically integrated state owned national utility, which operates the power and heat systems. It was supervised till recently by the Fuels and Energy Department of the Prime

118. It uses imported Bauxite with high transportation costs and faces a very difficult financial situation, caused inter alia, by the fluctuating demand and prices for Aluminum.

Table 2: Electricity Tariff Changes in Tajikistan Tajik Rubles/kWh (US cents/kWh)

Item	1997	1998	1999	2000
Residential consumers	0.20 (0.04)	0.50 (0.06)	—	—
Below 150 kWh/month	—	—	2.50 (0.21)	5.00 (0.25)
Above 150 kWh/month	—	—	8.50 (0.70)	11.00 (0.55)
Industry				
TadAZ	7.28 (1.35)	4.90 (0.63)	7.60 (0.63)	12.60 (0.63)
Others	7.28 (1.35)	7.30 (0.94)	11.34 (0.94)	18.80 (0.94)
Commercial	10.78 (2.00)	10.49 (1.35)	16.29 (1.35)	27.00 (1.35)
Agriculture	8.09 (1.50)	10.49 (1.35)	16.29 (1.35)	27.00 (1.35)
Water supply/other Government	0.50 (0.09)	0.50 (0.06)	2.50 (0.21)	2.50 (0.13)
Average Tariff/kWh	4.166 (0.773)	2.789 (0.359)	4.430 (0.367)	8.96 (0.448)
Exchange Rate: Tajik rubles/US$	539	777	1207	2000

Minister's Office. After the creation of a new Energy Ministry in October 2000, the Ministry supervises the sector and handles the responsibilities for policy and regulation. Barki Tajik has separate enterprises for generating units, transmission systems and electricity and heat distribution units, but they all operate as divisions of the national utility, rather than as independent entities. It has recently been corporatized and made into a joint stock company.

In the context of the IMF assistance under its Poverty Reduction and Growth Facility and ADB assistance under its Post Conflict Infrastructure Program Loan, the Government formulated an Energy Sector Policy Statement in 1998 which emphasizes its commitment to market based reform and defining the Government's role as a regulator. It envisages: (i) increased role of private sector in providing energy services; (ii) improved management efficiency and cost recovery in the enterprises still remaining under government ownership; and (iii) adoption of market based pricing. Under the technical assistance provided by the ADB, the government has formulated an Energy Sector Action Plan which involves: (i) enactment of a new Energy Law by October 2000 to encourage private investment in the sector; (ii) creation of the necessary legal and regulatory infrastructure for the efficient operation of the sector by 2002; (iii) raise the level of tariffs to match the full cost recovery level by 2004; and (iv) promote energy conservation from 2001 onwards. The Action Plan focuses on targets for management improvement, modernization of accounts and audit, improvements in metering, billing, and collections, reduction of accounts receivable and other aspects relating to the corporatization and commercialization of Barki Tajik. These have also become covenants under the subsequent ADB loan to the Tajik power sector and have been endorsed by IMF. The Energy Law had been passed and the Ministry of Energy has come into existence. Preparation of the Charters and subordinate legislation is underway. The law also provides for immediate involvement of the private sector in green field projects and in taking over specific assets and developing them. Barki Tajik is scheduled to be eventually unbundled into separate generation, transmission, and distribution companies. After this the distribution company to be privatized would be selected and the privatization process will be set in motion.

The institutional framework in the country, at present, is clearly not suited for the operation of competitive power sector. The rule of law is at the very early stages of development and contractual rights in general, and claims against the state in particular, are considered generally very difficult to enforce. There is very little commercial orientation and it may be very many more years before the power sector is operated by the private entrepreneurs on a competitive basis. Operating within these limitations, the Bank is pursuing the possibility of facilitating a non-profit, non-governmental organization - Aga Khan Foundation (AKF) - to complete the construction of Pamir 2 hydroelectric

project (14 MW), rehabilitate the generation, transmission and distribution network and operate the electricity system as a vertically integrated utility for a period of 25 years under a concession arrangement in the electrically isolated southeastern part of the country called Gorno Badakshan Autonomous Oblast. It is envisaged that a new company will be set up under the name Pamir Energy Company (PEC) with an equity contribution of $7.6 million by AKF and $3.3 million by IFC, which will also lend to the company $4.3 million. The Bank will provide an IDA credit of $10 million to the government for re-lending to PEC. PEC will complete the project with a total of $25.2 million thus raised and would also raise funds to meet the cost overrun if any. Tariffs would be maintained at a level adequate to provide a 10% return on equity[119]. Costs of social protection (needed in this context for the provision of lifeline rates and making the tariff increases for residences gradual) would be met from a Swiss government grant of $5.0 million and the re-lending margin of the IDA credit. While the scale of operation is admittedly modest,[120] it is an imaginative attempt to promote private investment to improve the electricity supply efficiency in the most impoverished and isolated part of the country. It also represents "thinking outside the box," by escaping from the standard prescription of unbundling, competition and privatization, which does not make much practical sense in this remote area and environment.

In respect of the remaining power facilities with Barki Tajik, it is best to focus on the corporatization and commercialization aspects and bring BT's operation to a reasonable level of efficiency, before embarking on sector restructuring and privatization. This will also give some time for the evolution of political and economic environment and the legal and market infrastructure needed for the smooth functioning of privately owned power facilities. Given the small size of the power system and the peak demand, introduction of competitive power pool arrangements would be unpractical, and other possible methods of private sector involvement such as management contracts, leasing arrangements and the like may have to be thought of. Meanwhile it may be useful to focus on the evolution of clearly defined unbundled tariffs for generation, transmission and distribution, and the possibility of third party access to the transmission and distribution system on the basis of nondiscriminatory tariffs for wire services so that at least the large industrial consumers could at a later date be given the choice of buying from a supplier of their choice on the basis of bilateral contracts, in the context of the Central Asian countries (Kazakhstan, Kyrgyz Republic, Tajikistan and Uzbekistan) operating a well interconnected transmission network (some what on the lines of the Baltic Market). Even ahead of this TadAZ which receives supply at 500 kV should be cut loose from BT supply and be allowed to shop around for its supplies. Simultaneously it may also be worth the while to focus on the development of strong transmission links among these countries to facilitate the evolution of a regional electricity market. ADB appears to be preparing some related projects in this regard.

The Government seems to be keen on constructing a good number of very large hydro projects, which may not be the least cost way of meeting the country's electricity demand with a low load factor and high seasonal variations. The least cost method would most likely involve the use of a mix of base load thermals and a mix of storage and run-of river hydro units. Construction of very large hydro units in such a remote area with security and seismic problems is likely to be very capital intensive as well as risky, and can be thought of only in the context of firm and adequately remunerative export contracts from a solvent country like China and is best undertaken by a consortium of foreign private entrepreneurs. Technical assistance to discourage the government from pursuing high cost and unpractical hydro options and to help the government to get optimal returns (by way of royalty, profit tax, concession fees etc) from such export oriented projects would

119. The average tariff/kWh is expected to grow from US Cent 0.75 in 2002 to US cents 3.0 by 2010 and remain at that level thereafter. The levelized tariff over the 25 year period would be US cents 2.1/kWh.

120. The overall transaction cost may be very high, compared to the modest size of assistance provided to the country.

appear to be appropriate. IFC and the Bank and other donors such as ADB may also play a useful role in assisting in the formulation of such export projects, in securing the cooperation of China, and in identifying and encouraging the private entrepreneurs to take interest in such a project using the range of instruments at their disposal, such as equity, debt, and guarantees for credit and against risk. Meanwhile the focus has to be on improving the operations of Barki Tajik, commercializing its functioning, timely and adequate adjustment of the tariffs and meaningful and targeted protection of the poorer consumers.

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TURKEY

Introduction

With a population of 65.3 million and per capita GNP of $3080, Turkey's economy, has been facing a series of economic crises during the last 10–12 years and is currently recovering from a deep recession. Its GNP growth,[121] which was 6.3% in 2000, turned to a negative 8.5% in 2001. Recovery to positive growth rates is expected in 2002 and 2003. Its annual rate of inflation rose from 38% to 69% in 2001. The exchange rate which was Turkish Lira 580,000 to a dollar in 2000 fell below TL 1.6 million in October 2001 and has since stabilized at around TL1.3 to 1.4 million to a dollar. Its external debt was estimated at 78% of its GNP.

Turkey's domestic production of oil (63,000 barrels/day) meets only 10% of its demand, and the rest is imported from the Middle East and Russia. Domestic annual production of natural gas (30 billion Cubic feet) meets only 7% of the domestic demand and the rest is imported from Russia as gas and from Nigeria and Algeria as LNG. It has high sulfur hard coal reserves of 1.1 billion tons, and high sulfur and low calorific value lignite reserves of 8 billion tons. Annual production of lignite was at 74 million tons in 1999 most of which went for power generation. The country's hydroelectric potential is estimated at 31,000 MW of which 10,500 MW had been developed by 1998 and another 3200MW was under construction. It is believed that the country has significant potential for wind power and geothermal power (35,000 MW).

Sector Dimensions and Characteristics

Turkey's installed power generation capacity had grown from 17,209 MW in 1991 to 27,264 MW in 2000. The generation capacity in 2000 also included nearly 3000 MW of captive generation plants of large industries (referred to as autogenerators), which supply their surplus power to the

[121] During 1991–2000 the country's average annual GDP growth rate was 3.7% and its annual inflation rate ranged from 65% to 85%.

grid and met a system peak load of 19,390 MW. Of the total installed capacity of 27,264 MW, 25.6% was coal or lignite fired, 33.3% was oil or natural gas fired, and 41% was hydroelectric. The rest were geothermal or wind power plants. The system operated at a relatively high load factor of 73.5%.

As at the end 2000, the transmission system consisted of 13,875 km of 380 kV lines, 84.6 km of 220 kV lines, 27,885 km of 154 kV lines, 682 km of 66 kV lines for a total transmission length of 42,527 km. The total transformer capacity was about 59,983 MVA. The system is interconnected to those of Azerbaijan, Georgia, Bulgaria, Iran, Syria, Armenia and Iraq. Main electricity imports are from Bulgaria (about 3 TWh a year), and partly from Georgia and from Russia via Georgia. From being a net exporter in the mid 1990s, Turkey is now a net importer with net annual imports of about 3.4 TWh.

Electricity generation in 2000 in the country totaled 125 TWh of which about 25% was from hydro power plants, and 75% was from thermal power plants. The contribution from wind power and geothermal units was 109 GWh (less than 0.1%). Generation had grown since 1991 at an average annual rate of about 8.4% and is forecast to grow at an even faster rate in the coming decade, as per capita consumption at 1700 kWh is considered low compared to those of OECD countries. However on account of the deep recession of 2000, the demand growth has decelerated. In 2001, supply and demand were broadly in balance. In 2002, an additional capacity of 4950 MW would come on line (on a "take or pay" basis), when the supply capacity will be higher than demand. Such excess new capacities coming on line up to 2004 could be managed by not using hydro plants and letting reservoirs to fill, but thereafter, some capacities might become stranded.

For the year 2000 an auxiliary consumption of 5%, transmission losses of 2.6% and distribution losses of 16.4% have been reported. While the level of the first two are reasonable, the distribution losses are high and are apparently rising. Review of data for 2001 and some sample surveys by consultants have shown that in 2001 the distribution losses as a percentage of electricity purchased by the distribution regions have grown to 20.4% consisting of technical losses of about 7.5% and non-technical or theft losses of 12.9%. The actual distribution loss figures range from 10% to 60% among the 33 or so distribution regions. About two thirds of the regions seem to have loss figures around 20% and the rest at higher levels. This compares with 5% to 6% distribution losses in European, Japanese and US utilities.

In the context of deep recession and high inflation, collections seem to have deteriorated somewhat. Though in terms of covenants with the Bank the level of accounts receivable should not exceed the equivalent of 30 days' sales, the actual accounts receivable level were in excess of 2.9 months' sales at the wholesale level and 3.5 months level at the distribution level in 2000. Collection is still considered a cause for worry in most of the backward regions.

Increasing fuel prices, runaway inflation and steeply falling foreign exchange rates have all combined to make tariff adjustments more than normally difficult. Still fairly frequent (often monthly) tariff adjustments had been made and the average retail tariffs without VAT (19%) and other taxes (6%) reached US cents 5.8/kWh by mid 2001. The average wholesale tariff at the same time was about US cents 4.5/kWh. As of May 2002, the retail tariffs including VAT and other taxes is about US cents 9.8 /kWh, which is considered rather high compared to the prices prevailing in the region as well as in West Europe. At the same time the wholesale price is US cents 5.6/kWh without VAT and other taxes.

Structural Changes

Turkish Electricity Authority (TEK) was established in 1970 to be responsible for electricity generation and transmission in most of the country. In addition, there are two small vertically integrated utilities (operating on long-term concessions) from the early 1950s, Chukurova Electric (CEAS) and Kepez Electric (KEPEZ). The former had an installed generation capacity of 580 MW hydro plants and 100 MW of oil fired thermal plant and supplied the Adana-Icel province. The latter had 127 MW

of hydro capacity and supplied the province of Antalya in the west Mediterranean Region.[122] Distribution, which was handled by the municipalities till 1982, was transferred to TEK in that year, thus making TEK a national vertically integrated utility fully owned by the state. Though under a law of 1985, TEK as a Public Economic Enterprise would be entitled to set its own tariff, the government in practice had the right to make changes therein and compensate the utility, if needed, with appropriate subsidies. The government also set the policies for energy planning, pricing and reviewed the annual investment plans of TEK.

During the period 1982–1991 TEK's generation capacity more than doubled from the level of 6,600 MW, financed by internally generated cash and government guaranteed external borrowing. During the foreign exchange crisis of 1993–1994, the country had a stabilization and adjustment program and in that context TEK was split into two entities, Turkish Electricity Generation and Transmission Company (TEAS), and Turkish Electricity Distribution Company (TEDAS), to enable possible eventual privatization. Under the IMF standby agreement of the 1995, Turkey's access to foreign debts was severely limited by the imposed debt ceilings. By 1996 the retail tariffs had reached US cents 7.1/kWh compared to the average of US cents 7,76 in OECD countries. Load was forecast to grow at well over 8% per year and annual investments of the order of $2.5 billion were envisaged to meet the demand. Thus "business as usual" of financing system expansion with internal cash and government guaranteed debt became increasingly difficult and appeared to have reached its limit. In this context the government opted to privatize the generation assets of TEAS and the distribution assets of TEDAS and also look to the private sector for constructing the needed additional generation capacity.

However, the constitutional court of Turkey issued a series of rulings in 1994 and 1995, which made the privatization very difficult, as the industry was regarded as a public service. The government came to the conclusion that privatization would not be possible without a constitutional amendment, and they could get such amendment passed only by August 1999. Meanwhile the government decided to adopt the concepts of "Build, Operate and Transfer" (BOT) and "Build, Operate and Own" (BOO) for adding new generation capacity to meet anticipated demand and giving the existing generation and distribution facilities on long term lease on the basis of "Transfer of Operating Rights" (TOORs) for a substantial up-front fee, determined on the basis of competitive bidding.

BOT contracts were given for a period of 15 to 20 years with government guaranteed "take or pay" agreement signed by TEAS for buying 85% of the plant output. The initial set of BOT contracts (three thermal power projects and two hydropower projects for a total capacity of 1,900 MW), which were awarded on a negotiated basis, without competitive bidding, had onerous terms and high electricity prices.[123] The three thermal plants (1,154 MW) were commissioned in 1999 representing about 4% of the system capacity and 6% of the system generation then. Though these units operated well and supplied reliable power, their prices were high enough to impact adversely the financial viability of TEAS.[124]

Five thermal plants with a total capacity of 5,830 MW, were given on BOO basis to three consortia including Shell, Bechtel and National Power, on the basis of competitive bidding. The prices obtained in these cases were about 60% of the prices obtained in BOT cases, though these contracts

[122] The system statistics report of TEAS for 2000 indicates that during 1988–1992, ten much smaller concessions were granted to private entities to carry out generation, transmission and distribution within their franchise area in certain provinces.

[123] It would appear that 25 more cases of BOT cases were approved, since the Aide Memoire of the Bank mission of June 2002 speaks of the need to approve 16 out of the 29 BOT contracts.

[124] Including purchases from autogenerators, holders of BOT contracts and TOOR contracts and other private generators, the share of the purchased power in the total power available to TEAS increased from 7.9% in 1991 to 22% in 1999. In 2000 TEAS's own generation was only 74 TWh (or 59%) of the total generation of 125 TWh in Turkey. Rest came from Autogenerators (16 TWh), CEAZ & KEPEZ (2 TWh), TOORs (1.1 TWh) and BOT/BOO generators (31 TWh).

also involved government guaranteed take or pay provisions. 3,850 MW of these would be commissioned in 2002 and the rest in the next year.

In addition the government had been encouraging industries to build their own captive generating units (autogenerators), and supply their surplus power to the national grid, by offering them appropriate prices. They were also given suitable transmission tariffs for transmitting their own power to their industries, if they happen to be in different locations. In 2000, these autogenerators provided 3000 MW or 11% of the system capacity and 16 TWh or 15.4% of the system energy.

Under the TOOR arrangement 25 of the 29 distribution areas were offered for long-term lease. Of the remaining 4, CEAZ and KEPAZ covered two and the other two, Aktas and Kasyseri, had been operating as private distribution concessions for a long time. By April– May 1998 the leases were awarded to the highest bidders. Six of these got involved in legal disputes and made no progress. All the bidders were Turkish firms, which were unable to attract foreign investors to join them, because of their low margin bids. The Russian crisis of 1998 made it difficult for them to secure finances for the up-front fee. Eleven packages covering 12 generating plants were offered for TOOR and awarded to the highest bidders. Several of these bidding groups had foreign investors in them. Only one of these could be finalized, and the Cayirhan Power plant was awarded to a Turkish firm, Park Energy. The remaining 11 are to be cancelled if they could not be finalized soon.

While the TOOR transactions were pending, the government succeeded in getting the constitution amended in August 1999, permitting the privatization of public utility services and allowing international arbitration for resolving disputes. Parliament was authorized to determine the assets to be privatized. This development cooled the enthusiasm of the government for TOOR arrangements and it delayed the finalization of the TOOR deals. By March 2001, a new Energy Market Law was enacted empowering the Privatization Authority to privatize power generation and distribution assets. The Energy Market Law contained provisions to the effect that cases of TOORs not fully finalized and signed by 30 June 2002 could be cancelled and the related assets included in the assets to be privatized. The constitutional court has since ruled those provisions unconstitutional. The government's plan is to modify the terms of TOORs in the light of the new market arrangements and EMRA regulations envisaged and finalize them. Those not amenable to such finalization may have to be cancelled and included with others for privatization.[125] The developments in this regard have to be watched carefully.

However, foreigners cannot have controlling interests in respect of such privatized assets. The Energy Markets Law also created the Energy Market Regulatory Authority, as the independent regulatory body for electricity and gas sectors. The law enables the introduction of competitive models of the market and establishes a framework for the full privatization of the sector. The regulatory authority had been set up and has become functional since late 2001. Though presently the tariffs are being set by the government, EMRA is expected to handle tariff setting as soon as the preliminary set of regulations are issued sometime later in 2002.

As a prelude to the new competitive market arrangements, the government had unbundled TEAS into a generation company, a transmission and load dispatch company and a energy trading company by a Decree. The last entity was to hold the BOT and BOO contracts and also to buy the generation of the generation company and sell them in the wholesale market. However, Danistay, a high level administrative court had invalidated such unbundling in June 2000. The Government had thus to amend SEE Law (No.233) in February 2001 to legally unbundle TEAS and the unbundling orders were reissued in March 2001. Thus with effect from March 2001, three new companies in the place of TEAS came into existence. They are Turkish Electricity Generating Company (EUAS). Turkish Electricity Transmission company (TEIAS) and Turkish Electricity Trading and Contracting Company (TETTAS). TEIAS with the help of consultants is preparing the generation and distribu-

[125] Presently TOORs is not considered a well conceived option, as it does not seem to provide any incentive to the lessee to make any new investments or even efforts to make efficiency improvements. The lease agreements do not appear to have been prepared to cover these issues adequately.

tion grouping to form competitive companies. Documents for the prequalification of the bidders for the privatization of the distribution companies are also under preparation. EMRA with the help of consultants is setting up regulatory procedures and market regulations.

Outlook for the Future

When a competitive model comes into operation, it is most likely to be in a form in which a substantial regulated market would coexist with a significant competitive segment with scope for gradual and orderly expansion for the competitive segment conforming to the EU requirements. The Energy Market Law provides for regulated third party access to the wires network and for nondiscriminatory and transparent tariffs for such wires services. To start with the eligible consumers would be those with a consumption above 9 GWh and would include the distribution companies. These eligible consumers could conclude bilateral contracts in a competitive environment with generators of their choice. TETTAS would buy power from state owned hydro power companies at regulated prices, from BOT and BOO entrepreneurs at the contracted price, and from the privatized generation companies at the negotiated prices and sell power at its average cost to the eligible consumers and distribution companies on the basis of bilateral contracts. It is expected that the market would be mostly by bilateral contracts and pool would be limited to balancing transactions only. Unless new constitutional or other legal problems crop up, the privatization should proceed smoothly on the basis of competitive bidding among financially sound local partners with strong partnership with strategic foreign investors (as the law does not allow controlling interests for foreigners). However the problem of stranded costs arising from BOT, BOO cases and the problem arising from TOORs cases not finalized yet would have to be tackled with care, and fairness to every one so that foreign and domestic investors are not scared away.

TEAS and TEDAS are well run utilities, which have more or less exhausted their potential for expansion as state owned companies. The country is moving towards new forms and structures to be able to meet the forecast massive increases in demand, and in that process has stumbled somewhat in experimenting with BOT, BOO and TOORs forms of involving private sector, and finally arrived at the need for competitive framework to promote further private investment. Its preparation for this, in terms of corporatization, unbundling, and commercialization are substantial. Once the market framework and rules are properly finalized, and the regulator commences his operations and gets into the groove, there is good reason to believe that the domestic and foreign investors will be greatly interested in entering this market with excellent growth potential. Turkey thus presents a case of careful preparation despite its unenviable macroeconomic circumstances.

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UKRAINE

Introduction

With a population of 50 million and a per capita GNP of about $750, Ukraine, among the FSU countries, took the longest time to emerge from the economic turmoil ensuing from the dissolution of the Soviet Union and resume growth. After nearly a decade of economic contraction, its GDP registered a 6% growth in 2000 and 9.3% growth in the first 9 months of 2001. Annual rates of inflation, which raged at 10,000% in 1993, came down to 40% in 1996 and further down to 13.2% in 2001. In the current year it is expected to go down below 10%. About 29% of the population live below the poverty line and 3% in extreme poverty.

Despite modest reserves of oil (395 million barrels) and massive reserves of natural gas (39.6 TCF), its domestic production of oil (84,000 barrels/day) and gas (0.6 TCF a year) meets only 25% and 21% respectively of the country's demand for these fuels. Its coal reserves are significant at 37.9 billion tons and its annual production of coal at around 91 million tons meets the domestic demand and leaves 2.5 million tons for export. Large dependence on imported oil and gas and the country's debts relating to them tend to cause uncertainties and supply disruption threats.

System Dimensions and Characteristics

The power system of Ukraine is very large and its present installed electricity generating capacity is estimated at 54,800 MW consisting of 12,800 MW of nuclear plants, 36,600 MW of thermal plants, 4,700 MW of hydro plants, and about 700 MW of small combined heat and power (CHP) plants, small hydro power plants and auto generators. Its main transmission voltages are 750 kV, 500 kV, 400 kV, 330 kV, and 220 kV. Sub-transmission is by an extensive 150 kV and 110 kV grid. Its distribution voltages are 35 kV, 20 kV, 10 kV and 0.4 kV. The country is estimated to have about 991,000 km of transmission and distribution lines of which 18,000 km are above 220 kV and another 50,000 km are in the sub-transmission category. The total transformer capacity is estimated at 126,224 MVA. In addition there is also a 800 kV HVDC link to Russia. The system is interconnected to Russia, Romania, Bulgaria, Belarus, with a total power transfer capacity of 11.000 MW. It serves a total of about 18.5 million consumers

Electricity generation declined from 296 TWh in 1990 to 157.8 TWh in 1999. During the same period consumption including losses had come down from 268 TWh to 146,7 TWh. In 1999, about 50% of generation came from nuclear, 10% from hydro power plants and 40% from thermal plants.[126] In 2000 generation is reported at 170.7 TWh and consumption at 166.9 TWh. In 2001 generation is believed to come down slightly to 167 TWh. In 1995 a transmission loss level of 9% and a total system loss level of 20% were reported. System losses have risen considerably since. In 2000, the distribution losses alone ranged from 20 to 32% in various distribution companies. Tariffs for households are uniform all over Ukraine and the average tariff for the households stood at US cents 2.13/kWh at the end of 2001. The tariffs for other non-residential consumers vary from region to region. However the average revenue per kWh from industrial consumers for the whole country was about US cents 2.38, while that for all consumers was US cents 2.45.

Non-Payment Problem

Ukraine's electricity sector had been facing an extremely serious problem of non-payment and non-cash payment since 1994. Macroeconomic stabilization involving major attempts to contain the fiscal deficits and runaway inflation through the use of tight money policies and high interest rates was followed at a time when the imported fuels reached world prices and the domestic and export demands collapsed. The state owned industrial enterprises thus started defaulting in utility payments. Budget financed entities did not have adequate provisions in their allocation to settle their utility bills. Thus the power companies accumulated huge accounts receivable. The option of disconnecting non-paying customers was denied to the utility companies through political intervention. Thus the electricity sector was effectively forced to provide credit to the rest of the segments of the economy. The electricity sector could not pay for the domestic and foreign suppliers of fuel and every one was in tax arrears to the government. Any cash in the accounts of any company was subject to seizure by the tax authorities for tax arrears. In this context the use of non-cash forms of payment such as offsets, vexels (promissory notes) and barter emerged and quickly engulfed the economy. Collections and cash collections went down steeply. The collections at the distribution level went down to 60% to 70% and cash collection to less than 15%. At the level of the wholesale market and the generators the percentage of cash was even lower.[127] This kind of a situation prevailed in slightly varying degrees practically right through the decade. Another major consequence of this non-payment phenomenon was that lack of cash starved generators for wages and fuel and thus severe supply constraints developed while, ironically, the country had excess capacity and declining demand. System frequencies and voltage levels could not be maintained and the Ukrainian system had to be isolated from those of its neighbors for considerable periods of time.

Structural Changes

During the period 1991–1994, the power sector in Ukraine was organized in the form of seven vertically integrated regional power utilities reporting to the Ministry of Power and Electrification. The five nuclear plants were under the control of the State Committee, Goskomatom. Though demand had declined reducing the urgency for adding new capacity, the system was still in need of substantial investments for the replacement of ageing assets, rehabilitation of thermal and hydro generation assets, safety upgrades for the nuclear plants and for the creation of peaking capacities and better system control and automation. In the context of the economic turmoil and non-payment debacle, neither the sector nor the government could raise the funds needed. The government decided to seek investment funds as well as managerial expertise from the private sector. Privatiza-

126. In 2001 these shares were 47% thermal, 46% nuclear and 7% hydro.

127. Overall collections, which reached 90% including cash collection at 20% by end 1996 quickly deteriorated to 60% collections including 7% cash. Collections at the generation level were reported at 59% to 75% including cash at 5.3% to 7.7% during 1997–1999.

tion of the vertically integrated regional utilities as they were was not considered a politically acceptable option in a "fragile new state". After a detailed study of the various types of power sector reforms in the various parts of the world, the government decided to follow the UK model involving a wholesale market operating on the basis of a competitive pool and the license based regulatory system. Thus a decision was taken to reorganize the sector, unbundle it by function, and corporatize the unbundled entities. The intention thereafter was to privatize the distribution entities and thermal generation entities, and to retain nuclear and hydro generation as well as transmission and dispatch under state ownership.

Through a Presidential Decree issued in 1994 sector unbundling was carried out resulting in:

- Four Joint Stock Companies (JSCs) to own and operate 14 of the largest thermal power plants (36,600 MW) in the country;
- Two JSCs to own and operate 11 of the largest hydro power plants (4,700 MW) in the country;
- One JSC Energoatom to own and operate the five nuclear power plants (12,800 MW);[128]
- One JSC called Ukrenergo to own and operate the transmission grid and the national and regional load dispatch centers;
- 27 distribution JSCs one each for the 25 administrative regions (oblasts) and one each for the two major cities of Kiev and Sevastopol;[129]
- Several licensed electricity traders authorized to buy electricity from the wholesale market and sell to the large industrial consumers.

All generating companies were obliged to sell their generated power to the wholesale electricity market (WEM). The dispatch center was to receive hourly bids from each generator and system dispatch was to be on the basis of ascending bid prices. Every thermal generator which was dispatched was to get paid uniformly on the basis of system marginal cost for that hour.[130] WEM then sold power to the distribution companies and the licensed electricity traders at the pooled average hourly prices including the cost of transmission and ancillary services. The distributing companies sold power to end consumers on the basis of retail tariffs regulated by National Electricity Regulatory Commission (NERC). The electricity traders sold power to the large industrial consumers on the basis of unregulated negotiated prices. The market rules were embedded in the wholesale market agreement, which all participants in the market signed. The detailed accounting was done by the dispatch center and WEM was to collect the amounts from the distribution companies and electricity traders and pay the generating companies.

NERC was created at the same time as an independent regulator to regulate access to the transmission and distribution networks, to promote competition in the WEM, and to regulate the retail tariffs, which were to be a sum of the cost of the power purchased from the pool and the justified costs of the distribution company including depreciation and a reasonable profit margin. NERC was also to license and monitor all generating, transmitting, dispatching, and distributing companies and the electricity traders.[131] It was to ensure compliance by all participants of the WEM agreement, the grid code and associated regulations. The new Electricity Law passed by the parliament in October 1997 gave the legal basis for the existence of such a competitive market.

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128. Goskomatom was merged with the Ministry of Power and Electrification in 1997.

129. Some of these distribution companies had small sized generating stations and CHP units.

130. This payment arrangement was valid for the thermal generation only. In respect of nuclear and hydro units, regulated prices are adopted. Such price regulation is by NERC on the basis of covering all justified costs including depreciation and a reasonable profit margin.

131. As of 2002, NERC has issued one license each for wholesale supply and "main" transmission, 132 for power generation, 51 for power transmission by "local" lines, 41 for retail supply at regulated tariffs, and 608 for power supply at unregulated tariff rates.

The above structural changes were taking place in an environment the entire sector was reeling under the non-payment crisis, and when the system was suffering from severe supply constraints arising from a lack of funds to buy fuel and pay wages and the new arrangements got quickly entangled in the mess of non-payment and non-cash payment. When the distribution companies defaulted on their payments to WEM, NERC could not disconnect them, as the Ministry of Fuels and Energy would not let him. WEM had no way of handling barters and offsets in settlement mechanism, as there were no full disclosures of such transactions.[132] and no acceptable method of valuing even the partially disclosed transactions. Further the government did not appear to have fully grasped the essence of the new marketing arrangements, under which the retail prices were a sum of WEM selling price and the justified costs of distribution and a small profit. When the retail prices tended to rise as a function of higher WEM prices (caused by higher fuel prices and the high prices quoted by the generators in the context of severe supply shortages) in 1996, the government simply forced the regulator to leave the retail tariffs unchanged. The argument appeared to be that if tariffs rose, it would still not increase revenues, since most consumers did not pay. On the other hand such tariff increase would force the utilities to pay higher VAT and related taxes on the same quantum of power sold. The NERC thus got into the habit of declaring emergency and forcing the WEM to apply downward correction to the hourly marginal costs to balance the pool price with low retail prices.[133] The parliament restricted the right of NERC to determine the retail prices for residential consumers until the state budget's arrears for wages and pensions could be fully eliminated. Also the residential tariffs were made uniform all over the country. Thus all electricity companies accumulated huge arrears and it was becoming increasingly difficult to run the WEM in any meaningful way. All donors to the sector including the Bank became unhappy and either threatened to or actually cancelled their assistance.

Thus fighting non-payment became crucial to the survival of the marketing arrangement. Fortunately the reform oriented cabinet of ministers, which assumed office, adopted a transit account mechanism and enacted the needed laws and regulations to ensure that all payments to the distribution companies by consumers had to be remitted into a transit account. The proceeds from this account were periodically disbursed to the WEM, transmitter and the distribution companies based on the formula devised on the basis of WEM operations. Simultaneously laws were passed to discourage barters and offsets and other non-cash forms of payments.

Privatization

In the context of the Bank's loan for the Electricity Market Development Project in late 1996, the government had undertaken to privatize the distribution and thermal generation companies in "the medium to long term." Among other things it was believed that privatization of distribution companies would help to overcome the non-payment problem. For the distribution companies the government followed the policy of: (a) sale of 15% to 25% of the shares to employees and mangers for cash, or privatization vouchers or compensation certificates; (b) sale of 10% to 15% in the country's stock exchange or specialized certified auctions; and (c) sale of remaining shares on the basis of open commercial tenders. In the case of generation companies the policy was: (a) to sell 15% to 25% of shares to staff and managers for cash, privatization vouchers or compensation certificates; (b) to reserve 50% plus one share for state ownership for eventual sale by tenders; and (c) to sell the remaining shares by open competitive tenders in the first instance. In respect of the 27 distribution companies the first two steps were quickly completed and the stocks are trading in the local stock exchange. The government had thus 60% to 75% of the shares to start process of the third step.

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132. Both distribution and generation companies were reluctant to disclose the full details of their non-cash transactions. Circular transactions using promissory notes could go round generators, their fuel suppliers, construction contractors, energy traders and the distribution companies totally bypassing WEM arrangements.

133. Thus in effect the market never functioned in the way in which it was expected to function. It functioned as if all generation prices were regulated in a non-transparent and arbitrary manner for all practical purposes.

In December 1997, the State Property Fund issued the tenders for the sale of 20% to 25% shares in 9 distribution companies. The conditions attached to the sale were: (a) working capital had to be replenished; (b) overdue accounts payables had to be settled; (c) financing of the rehabilitation programs should be undertaken; and (d) social infrastructure should be maintained. Only local entrepreneurs responded to the tender and 20% shares only in two distribution companies could be sold. Both went to local private financing institutions. In June 1998, the State Property Fund issued tenders for several distribution companies, but sale could be concluded only in respect of seven. This time 35% to 36% in each company was sold. This round also did not attract any foreign strategic investor and all successful bidders were local companies, which were buying either buying on behalf of some offshore companies or for sale to some one else within a short time. Sale proceeds at UAH 434 million (or about $80 million) was modest. The buyers quickly got majority and control of the distribution companies, by buying additional shares from staff and managers and from the stock exchange.

The performance of the newly privatized companies was not considered helpful. They failed to play by the rules of WEM and make timely or full payments to WEM. It is believed that they contributed to the continuation of the non-payment and non-cash payment problems by accepting non-cash payments and by not taking action against delinquent customers. Seven of the privatized companies had an accumulated debt of UAH 2.9 billion. Thus the need for the Transit Account mechanism (discussed earlier) arose in this context.

Three important improvements took place before the next round of privatization. First the donors as a group pressed for stricter criteria for the pre-qualification of the bidders to ensure that only those with adequate utility management experience as well as adequate financial resources are qualified. Second NERC had announced new tariff methodology under which the retail tariff levels would allow 17% return on existing investment and new investments for a period of 7 years and 11% for the next 5 years. Any distribution company can qualify to be covered by this methodology by: (a) concluding a debt restructuring agreement with WEM for outstanding debts and abiding by it; and (b) by remaining current on all of its dues for the electricity purchases from WEM starting from the date of the debt restructuring agreement mentioned above.[134] The distribution company which qualifies for this tariff methodology may also opt out of the transit account arrangements, as long they continue to pay 100% of their dues to WEM in a timely manner. Third, Credit Suisse First Boston was selected on the basis of competitive bidding as the privatization advisor and bidding documents and arrangements were made on the basis of their advice.

Initially 51% to 75% of the shares in 7 distribution companies was covered in this round. One company was later dropped on account of some local legal problem. The seven strategic investors pre-qualified were: AES, EdF, Union Fenosa, VSE (of Slovakia), Kansai Electric, Bewag, and Cinergy[135]. Tendering took place in April 2001. AES, EdF and VSE submitted 8 bids for the six distribution companies. AES purchased 75% shares in two distribution companies and VSE got 51% to 75% shares in the remaining four at a modest total cost of $160 million. Russian investors are believed to be providing the financial resources for VSE for this acquisition. Russians are also reported to remain keenly interested in further such acquisitions especially in the areas on the route from Russia to Western Europe to earn transit fees on future exports of electricity from Russia to West Europe.

The introduction of the transit account, and the new tariff methodology as well as the overall improvement in the economy through resumption of growth and lowered inflation have all contributed to the improvement of collection and cash collection in the sector in the last 12 to 15 months. About 10 distribution companies were collecting well over 100% of their current bills, and overall collections were believed to be around 80% to 90% with cash at 66% to 76%.

134. See Resolution # 309 of NERC dated 2 April 2001 and Resolution #348 dated 10 April 2001.
135. RAO UES of Russia did not qualify.

In May 2001, permission given earlier for the special treatment of the circular offsets among the generators, coal mines and railways (called one day credit scheme) was withdrawn and this resulted in collections reaching 95%.[136] On the whole it would appear that the problem of non-payment is getting under control.

However the problem of dealing with the huge debts accumulated by the electricity entities in the past still remains, and is the focus of the government's attention under the on-going adjustment lending operation. The debt situation as of January 2002 is summarized below:

Debts from	Debts to	Amount in UAH billion
End consumers	Distribution companies	8.4
Distribution companies	WEM	12.9
Electricity traders	WEM	0.2
WEM	Generation companies	13.3
Generation companies	Fuel suppliers and other creditors	15.6

The largest share of debts to the electricity sector was that of industries (37.2%) followed by communal services (25.1%), households (16.8%) and agriculture (12.1%). The share of debts by state and local budgets and railways together was about 2.34%. A recent consultant study on the situation of generation companies indicates that, as at the beginning of 2002, WEM has a debt of UAH 6.3 billion to the four thermal generation companies, which, in turn, had a debt of over UAH 4.7 billion to their fuel suppliers. At the same time, overall debt of WEM to all generators (including hydro and nuclear) amounted to UAH 13.3 billion and the generators' debts to their creditors amounted to UAH 15.6 billion. Thus fuel suppliers move for the bankruptcy proceedings against generation companies and force the sale of assets in auctions, giving rise to the phenomenon of "asset stripping." A state-owned gas trading company sued Donbassenergo, one of the four major thermal generation companies, for non-payment of fuel debts and the bankruptcy court ordered the company's assets sold to settle the arrears. The auction was not publicly announced until after one week of the auction 4,160 MW of thermal units were sold for $38.2 million in May 2001. Fortunately the Ukrainian government stepped in and annulled the sale in June 2001. Similar asset stripping also takes place in relation to distribution companies for their debts. Recently, Donetskoblenergo, the largest and the most troubled among the distribution companies, was forced by a bankruptcy court order to sell key segments of the transmission grid for a throwaway price. In order to prevent such preemptive asset stripping ahead of proper privatization, the parliament has passed a Moratorium Law and it is expected to secure the President's signature soon.

The government has identified the debts of all state owned enterprises and budget entities as of January 2001 to the distribution companies and is closely monitoring the changes in debt, legal actions to recover them, and physical disconnection of supply. The debts of distribution companies to WEM as of January 2001 are being restructured into a new five year medium term debt with two years of grace period followed by quarterly payments thereafter. Terms of privatization obliges the privatized companies to pay in cash full amount of current dues of WEM. The new tariff methodology acts as the incentive. The debts of generation companies need to be similarly restructured before their privatization. Debtors to distribution companies would be appropriately classified into: (a) solvent debtors who have debts on account of their past liquidity problems; (b) insolvent debtors who cannot be cut off because of their strategic or environmental importance; and (c) other large insolvent debtors who are likely to become bankrupt. The debts of the first would be restructured, for the second, the state budget would develop a suitable mechanism for financing, and for the

136. Cash collections appear to have reached about 90% at the same time.

third, actions to realize debts by moving them to bankruptcy, and if they fail, writing off debts would be followed.

In June 2001 Credit Suisse First Boston had again won a competitive bidding and been appointed as privatization advisor for the next round of privatization of distribution assets. Initially 51% to 75% of the shares in 12 companies[137] were included for this round, and as of now it would appear that only 9 will go forward as the other 3 are tied up in court cases. Some key details of the 12 companies is given below to gauge the large size of the transaction.

SOME KEY DETAILS OF THE 12 DISTRIBUTION COMPANIES OFFERED FOR PRIVATIZATION

Distribution Company	No. of consumers	No. of employees	Sales GWH (2000)	Info. on generation	System losses	shares for sale
Cherkasy	609,858	4650	1934	Has CHP	23%	70%
Chernivtsi	336,619	1356	866	HOB	22%–27%	70%
Dnipro	1,436,291	7480	14,967	Has CHP	7% to 8%	75%
Donetsk	1,859,458	10592	13315	160 MW + CHPs	14 to 15%	65%
Kharkivo	1,168,511	10697	4405	None	20 to 21%	65%
Khmelnitsk	560,325	2681	1485	2.36 MW + CHPs	22%	70%
Krym	738,779	6947	3473	CHPs	27 to28%	70%
Ternopil	410,732	1985	886	CHPs	29 to30%	51%
Vinnitsya	778,937	3386	1847	21.3 MW + CHPs	31 to 32%	75%
Volyn	336,708	1754	738	None	33 to 35%	75%
Zakarpattya	384,240	1881	1037	33.6 MW + CHPs	40 to 42%	75%
Zaporizhya	735,867	4126	7397	None	11.5 to 14%	60%

Note: Sales in GWh relate to 2000. Most other data relate to earlier years.
Source: www.imepower.com and Power in East Europe, issue dated 4 March 2002

The pre-qualification criteria would appear to be about the same as the one adopted for the last round except that the key qualification is ownership of, and experience in, distribution utility operation and or generation capacities of 1000MW or above. A Task Force of donors and the government are reviewing this carefully. The tendering exercise is expected to commence in the next few months in the 3rd quarter of 2002. Minority shares held by the government in the 7 companies sold in the second round are also expected to be sold but they may not attract the attention of the strategic investors as the Russian interests have already majority shares in them. Meanwhile the government is working on getting new laws approved by parliament to give legal authority to the functioning of the WEM and to give greater autonomy and independence to NERC. In order to prevent concentration of market power, the government has stipulated that no investor should own more than 3 contiguous distribution companies. Neither can one have more than 15% of the total national electricity sales

Now that the non-payment situation is coming under control, the privatization procedures have become improved and more transparent, and more attractive retail tariff terms have been ensured, one may hope that there would be even greater interest of the international strategic investors to respond to the future bids and offer even better prices. When the privatization of the thermal generation companies and distribution companies are completed, the competitive market would be able to operate on a competitive basis. The retention of the hydro and nuclear plants under the ownership of the state and their operation on the basis of regulated tariffs would moderate possible retail tariff volatility under the market arrangements and thus, hopefully, restrain

137. The 12 companies considered for the next round have consumers in the range of 337,000 to 1.9 million and annual sales in the range of 929 GWh to 10,762 GWh and include some of the largest distribution companies in Europe.

the parliament from overriding the orders of NERC. Eventually the society will reap the rewards of competition, when the government divests these assets also in a transparent and competitive sale.

Considering the size of the Ukrainian power system, the competitive pool model chosen for the sector reform was probably considered appropriate. Unfortunately it was done at a time at which the non-payment crisis was at its peak and while the system was suffering from serious supply constraints and shortages and thus got quickly swamped by these. Under the arrangement adopted, there was no room for bilateral contracts between generators and distributors and the payments for the entire sales had to pass through the WEM. A dispatch based primarily on bilateral contracts and WEM operating only as a balancing pool would have reduced the problem considerably, since only a small amount of the money relating to the balancing power sales will pass through WEM. Bilateral contracting could have helped to overcome the non-payment problem somewhat, but prices may have gone up and the NERC would be hard put to assess the reasonableness of the prices paid for power by the distribution companies for regulating the retail tariffs. Currently a working group in Ukraine assisted by consultants is reviewing the options for revamping the market mechanism to make it practical under the circumstances prevailing in Ukraine and to give a sense of security to the prospective investors in generation and distribution.

The case of Ukraine illustrates the need to overcome non-payment problems, before attempting to introduce sector restructuring and sophisticated competitive market models. Unbundling may actually have exacerbated the non-payment problem, though it undoubtedly brought into focus the problems at the distribution level. Under the unbundled set up it becomes difficult for the generators to access any cash for payment of wages or purchase of fuel, thereby creating supply shortages, which aggravates the problem. In any case the problems of non-payment of current bills and the disposition of the past accumulated debts need to be resolved before any meaningful privatization and competition takes place. Simpler forms of the market with the coexistence of regulated and competitive segments would have been more appropriate for the circumstances of Ukraine. Also the issue of 15% to 25% shares to staff and managers another similar percentage through stock market seems to enable speculators to gain influence in a manner unintended by the government. Sale of minority shares in that context seems to land the companies in unexpected hands. The Ukrainian experience also emphasizes the need to settle tariff methodologies, protection against asset stripping, and transparent bidding among bidders selected through strict pre-qualification, to secure optimum results and the helpful role the donors could play when they give coordinated advice.

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